



Statement of Kenneth Seiler, Vice President of Planning, on Behalf Of PJM Interconnection, L.L.C.

FERC Technical Conference on Transmission Planning and Cost Management

**Docket No. AD22-8-000, Panel #3: Regional Transmission Planning for Reliability
September 27, 2022**

For Public Use

On behalf of PJM Interconnection, L.L.C. (PJM), I appreciate the opportunity to participate on this panel addressing the processes by which transmission providers evaluate, select, and develop regional transmission facilities for reliability.

My name is Ken Seiler. I currently serve as Vice President of Planning for PJM. I have included as Attachment A to this testimony my background and work history in the industry. As part of my work for PJM, I am responsible for activities related to resource adequacy, generation interconnection, and regional and interregional transmission planning, including the development of the Regional Transmission Expansion Plan (RTEP).

As set forth in the Commission's September 8, 2022 Supplemental Notice of Technical Conference (Notice), this panel will discuss: (i) how transmission providers evaluate potential regional transmission facilities for reliability to determine whether they could more efficiently or cost-effectively address an identified reliability need; and (ii) cost management practices that require coordination between local and regional transmission planning processes. The panel will also explore issues related to three specific questions as set forth in the Notice. Accordingly, I provide below: (a) background information about PJM's current process for planning for long-term transmission needs;¹ and (b) high level responses to the questions set forth in the Notice.

I look forward to discussing these issues further with Commissioners, Commission Staff and my fellow panelists.

A. Background on the PJM RTEP: Planning for Long-Term Transmission Needs

Long-term planning for the reliable delivery of wholesale power is one of PJM's main responsibilities. Currently, the PJM RTEP identifies the transmission needs of the grid up to 15 years into the future.²

¹ The Commission is currently considering comments on its Notice of Proposed Rulemaking in which it proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by changes in the resource mix and demand. See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, 87 Fed. Reg. 26,504 (May 4, 2022) ("NOPR" or "LTRTP NOPR"). PJM submitted extensive initial and reply comments in response to the LTRTP, which I have included as Attachment B (PJM LTRTP Initial Comments) and Attachment C (PJM LTRTP Reply Comments) to this testimony.

² In the LTRTP NOPR, the Commission has proposed to require transmission providers to develop Long-Term Scenarios as part of the proposed Long-Term Regional Transmission Planning process using no less than a 20-year planning horizon in order to "allow for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities." LTRTP NOPR at PP 92, 97-98. As explained in its initial comments, PJM continues to believe a 15-year planning horizon allows for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities while reducing input assumption risks associated with a 20-year horizon.

Annual Benchmark Report

PJM planners continuously analyze the transmission system to forecast what will be needed to keep the lights on for an estimated 65 million people in 13 states and Washington, D.C. Published annually, the RTEP report summarizes studies that help ensure that the system meets requirements for reliability, market efficiency, resilience, public policy and the needs of the transmission system owners.

Transparent Stakeholder Engagement

Throughout the year, the RTEP process identifies grid enhancement solutions through open, transparent engagement with members, stakeholders, regulatory agencies and other parties.

Several committees support the process. PJM's Planning Committee reviews recommended planning strategies and policies, as well as planning and engineering designs. The Transmission Expansion Advisory Committee (TEAC) provides a forum for stakeholders and PJM staff to exchange ideas, discuss study assumptions, and review identified transmission needs, and proposed transmission solutions to address them. Subregional RTEP committees address local planning concerns, mainly at 230 kV and below.

After stakeholder process review, PJM recommends projects to the PJM Board of Managers for consideration and approval only after which they are included in the RTEP.

The RTEP process does not review or approve the siting of transmission lines. Individual transmission developers must seek those approvals in the states where new facilities will be built. However, PJM takes into consideration infrastructure development risks as one of the factors in its project evaluation process.

Comprehensive and Efficient Transmission Planning

PJM's RTEP planning process encompasses two 18-month study cycles for reliability that overlap by six months, and one 24-month cycle for market efficiency studies. Market efficiency projects are designed to reduce congestion on the transmission system to help ensure that the lowest-priced power can be delivered across the grid. The 15-year planning horizon allows PJM to evaluate the need for larger transmission projects long before construction.

Transmission projects that emerge from PJM's RTEP process fall into several categories.

Baseline Projects

Baseline projects address reliability, market efficiency, operational performance, or public policy needs, which are based upon national and regional reliability standards or criteria. These projects address issues such as thermal overloads, voltage criteria violations, excessive short-circuit current, system dynamic and transient stability as well as congestion. After PJM identifies a baseline transmission need, PJM may open a competitive proposal window, depending on a project's required in-service date, voltage level and scope.

Network Upgrades

Network upgrade projects are transmission upgrades needed for new customers seeking generation interconnection, merchant transmission interconnection, or long-term firm transmission service.

Supplemental Projects

Supplemental projects are transmission expansions or enhancements by transmission owners to address local reliability needs, such as customer service and load growth, equipment condition, operational performance and risk, and infrastructure resilience. PJM evaluates these projects to ensure they do not cause reliability violations.

RTEP System Modeling

Credible, consistent power flow studies ensure that PJM develops robust transmission solutions to address identified reliability criteria violations. To accomplish this, each study cycle begins with development of a system model that incorporates the latest information and assumptions with respect to zonal load forecasts, generating resources, transmission topology, demand resources and power transfer levels with adjoining systems. PJM evaluates those assumptions with stakeholders at TEAC and Subregional RTEP committee meetings.

B. High Level Response to Questions in the Notice

1. How do transmission providers weigh the costs and benefits of potential regional transmission facilities for reliability when determining whether to select such a facility in the regional transmission plan for purposes of cost allocation? For example, how do transmission providers (whether RTOs/ISOs or non-RTOs/ISOs) evaluate cost vis-a-vis other evaluation factors (e.g., developer qualifications, use of existing rights of way, other benefits provided)? How effective are these processes?

Facility Selection from Competitive Window Process

Following the submittal of project proposals through an open proposal solicitation process, PJM conducts an initial review and screening that includes the following, as described in Section 8.1.1 of PJM Manual 14F: *Competitive Planning Process*:³

- *Initial Performance Review* to evaluate whether or not the project proposal solves the identified reliability criteria drivers that were posted as part of the open solicitation process.
- *Initial Planning Level Cost Review* to evaluate the submitted project cost by the project sponsor as well as any cost containment mechanisms that are relevant to the project proposal. Project cost estimates and scope are evaluated for reasonableness based on projects of similar scope and magnitude.
- *Initial Feasibility Review* to evaluate the overall proposed implementation plan and determine if the project, as proposed, can feasibly be constructed. The initial feasibility review may consider physical aspects, permitting, required approvals and overall timing.

Using the information obtained through the initial review, PJM selects project proposals to perform detailed performance, cost and feasibility reviews, as described in Section 8.1.2 of Manual 14F.⁴

³ PJM, *Manual 14F: Competitive Planning Process*, § 8.1.1 (rev. 9, Apr. 27, 2022), <https://www.pjm.com/-/media/documents/manuals/m14f.ashx>.

⁴ *Id.* at § 8.1.2.

- *Detailed Performance Review* – PJM will identify potentially applicable criteria that may impact project performance beyond that explicitly stated as part of the original problem statement and evaluate in the initial screening review the analysis that was performed by the project sponsors.
- *Detailed Planning Level Cost Review* – PJM will perform a review of the total project cost, including review of cost estimates submitted by the project sponsor and review of cost estimates that may be provided for upgrade work related to the proposed project which would be performed by the affected incumbent Transmission Owner(s). For this review, PJM may validate the total project costs through the use of an independent consultant, internal resources or combination of both as necessary. PJM will also evaluate the benefit of any cost containment mechanisms and may engage an independent consultant to assess the potential benefit of any cost containment/commitment.
- *Detailed Feasibility Review* – PJM may perform an in-depth review of the constructability of the project. This review will typically include an evaluation of project scope, complexity and constructability factors that impact the project cost and/or schedule including, but not limited to, right-of-way acquisition, land acquisition, siting and permitting requirements, project complexity, project coordination complexity, outage coordination and project schedule.

When multiple proposals pass the primary considerations, PJM determines the relevancy of a set of additional considerations that inform the decision to identify the more efficient or cost effective project to address the identified need(s). After determining which considerations are relevant to a given evaluation, PJM identifies the differentiating factors among the proposals under evaluation, as discussed in Section 8.1.3 of Manual 14F:⁵

- Cost or Cost Containment Mechanism
- Cost Estimate Review
- Grid Resilience/Performance
- Reliability Margin
- Project Execution Risk/Schedule/Timing considerations including Environmental impact risks, Project Complexity, Impact to existing facilities, Technology Considerations, Schedule, Siting and Permitting Risks, Right-of-Way (ROW) and land acquisition, Physical constraints, and Outage Impacts
- Sensitivity Analysis

PJM retains the ability to select a project based on all relevant factors. PJM's rationale with respect to the evaluation process and the resulting decision will be explained and reviewed at TEAC, and stakeholders will be given the opportunity to provide feedback related to each proposal window. Additionally, PJM will provide an end-of-RTEP cycle comparative summary table (including performance, constructability, cost and cost commitment).

⁵ *Id.* at § 8.1.3.

2. Are transmission provider-specific reliability standards considered in identifying regional reliability transmission needs as part of regional transmission planning, similar to the transmission provider-specific local transmission planning criteria used in local transmission planning processes? What are the benefits and drawbacks of this practice?

Yes, transmission provider-specific reliability standards are considered in identifying regional transmission needs as part of transmission planning. PJM does not distinguish between “Regional” and “Local” planning⁶ when applying reliability criteria to identify need for *baseline* transmission enhancements as part of its FERC-approved RTEP Process, as discussed in PJM Manual 14B.⁷ PJM’s RTEP Process tests the Bulk Electric System elements under its control - essentially down to 100 kV⁸ – based on defined NERC, regional, and FERC 715 Transmission Owner criteria. In addition, Local plans also include Supplemental Projects as identified by the Transmission Owners within their zone. PJM Transmission Owners plan Supplemental Projects that address a need to expand or enhance transmission facilities where the responsibility for planning to address such needs has not been transferred to PJM pursuant to the Consolidated Transmission Owners Agreement (CTOA). Supplemental Project planning is conducted under PJM Tariff, Attachment M-3.

NERC Criteria

As a Federally-approved independent RTO, PJM is responsible for ensuring the reliable and efficient operation of the electric transmission system in the PJM region. In order to ensure reliable transmission service, PJM prepares an annual RTEP and applies North American Electric Reliability Corporation (NERC) Reliability Standards to evaluate the reliability of the transmission system. PJM determines the required transmission enhancements and expansions that are needed to ensure that the NERC Reliability Standards are satisfied.

⁶ “Local” Plans and “Regional” Plans are defined in the PJM Operating Agreement: <https://www.pjm.com/library/governing-documents/>

- *Local Plans* encompass: (1) Supplemental Projects as identified by the Transmission Owners within their zone; and, (2) Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners’ planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements. Subregional plans are transmission expansion or enhancement rated below 230 kV, which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by PJM.
- *Regional Plans* encompass transmission expansion and enhancements rated at 230 kV or above, which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by PJM.

⁷ PJM, *Manual 14 B: PJM Region Transmission Planning Process*, (rev. 51, Dec. 15, 2021), <https://www.pjm.com/-/media/documents/manuals/m14b.ashx>.

⁸ In addition, PJM-led analyses also include analysis of and solutions for transmission facilities with nominal voltages below 100 kV to the extent such facilities are under PJM’s operational control.

More specifically, PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-4⁹ through a wide range of reliability analyses – including load and generation deliverability tests – over a 15-year planning horizon. PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. Reliability criteria violations may occur locally, in a given transmission owner zone, driven by an issue in that same zone. Violations may also be driven by some combination of regional factors.

PJM Regional Planning Criteria

PJM Regional Criteria go beyond and complement the NERC Reliability Standards. In PJM, examples include the following:

- *Light Load Analysis Criteria*, which ensures the transmission system is capable of delivering generating capacity during light load periods given that generation dispatch differs markedly from that under peak load conditions.
- *Winter Criteria*, which tests the ability of an electrical area to export generation resources to the remainder of PJM during winter peak conditions. PJM models generation based on a historical mix of generation types and output levels typically observed during winter peak conditions, including tests for gas pipeline contingencies.

Transmission Owner Criteria

Transmission Owner Criteria, like PJM Regional Criteria, complement the NERC Reliability Standards. The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria¹⁰ address specific local system conditions, such as in urban areas and ensures that the criteria used addresses the specific local needs of the TO zone. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings.

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. While transmission enhancements driven by TO criteria are considered RTEP baseline projects, they are assigned to the incumbent TO and are not eligible for proposal window consideration.

⁹ TPL-001-4 can be found on NERC's website: <https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf>.

¹⁰ TO criteria can be found on the PJM website: <https://www.pjm.com/planning/planning-criteria/to-planning-criteria>.

3. What changes to regional transmission planning processes, if any, could be made to improve the identification of more efficient or cost-effective regional transmission facilities for reliability to replace the need for local transmission facilities?

PJM's experience with its existing RTEP Process demonstrates that both regional and local baseline transmission needs can be determined holistically vis-à-vis consistent application of NERC, regional and FERC 715 Transmission Owners reliability standards for a grid comprising Bulk Electric System facilities down to 100 kV (and lower, in some cases). PJM agrees that holistic changes could be made to certain aspects of existing planning processes to the mutual benefit of both Regional and Local planning. Doing so may inherently ensure more efficient and cost-effective grid enhancements to meet the demands on the transmission system for a changing generation fleet, state and federal public policy and growing load pockets. In particular, PJM notes the following points, as discussed throughout its LTRTP Initial and Reply Comments and elsewhere, warrant FERC's attention with respect to transmission providers' planning processes:

- As set forth in PJM's LTRTP Initial and Reply Comments, the Commission should adopt a comprehensive proposal to address the concept of "Enhanced Reliability."¹¹ In particular, PJM urged the Commission to more holistically address issues related to Enhanced Reliability by: (i) including in any Final Rule a clear Commission commitment to ensuring enhanced reliability and directives to all transmission planners to prioritize such efforts; and (ii) using its convening authority to bring together the DOE National Labs, the North American Electric Reliability Corporation ("NERC"), the National Association of Regulatory Utility Commissioners ("NARUC") and transmission planners to develop more uniform measures of the appropriate level of interregional transfer capability within each Interconnection.
- Overall, PJM supports the Commission's proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by "changes in the resource mix and demand," which should result in more efficient or cost-effective regional transmission solutions. One such example within the LTRTP NOPR is the concept that transmission providers should be required to evaluate whether transmission facilities can be "right-sized" to address regional transmission needs identified in the Long-Term Regional Transmission Planning process.¹²

¹¹ As set forth in its Initial Comments, PJM proposes to define "Enhanced Reliability" as "[t]he ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event." PJM uses this term rather than the term "resilience," given concerns raised by some regarding the use of the term "resilience" and its being confused with a prior Department of Energy ("DOE") proposal, long since rejected by the Commission. See PJM LTRTP Initial Comments and PJM LTRTP Reply Comments.

¹² See PJM LTRTP Initial Comments and PJM LTRTP Reply Comments.

- Consistent with the recommendations set forth in PJM's LTRTP Initial and Reply Comments, the Commission should engage in a comprehensive examination of all drivers of transmission system expansion. This should include studying the impacts of new generation and deactivating generation as driven by public policy and market forces, enhanced reliability criteria, aging infrastructure, and growing load pockets to meet consumer demand. Doing so will ensure that necessary reliability-driven enhancements will be identified to enable grid transformation triggered by changes in resource mix and demand. Such evaluations could yield more cost-effective solutions in certain circumstances. PJM notes though that greenfield transmission-level voltage solutions may not always be the most cost-effective solution, given the practicalities of siting and building such facilities. Enhancements to existing sub-transmission level voltage facilities - *e.g.*, 230 kV or lower - may indeed be the more cost-effective solution to achieve the same level of reliability.

ATTACHMENT A



Kenneth S. Seiler

Vice President – Planning

Kenneth S. Seiler leads PJM's System Planning Division. Seiler is responsible for all activities related to resource adequacy planning, generation interconnection planning, interregional planning and transmission planning, including the development of the Regional Transmission Expansion Plan.

Previously, Seiler was the executive director of System Operations and was responsible for the reliable operation and coordination of the bulk power system, including PJM's real-time dispatch operations and near-term reliability studies. Seiler oversaw the dispatcher training and certification functions, as well as the markets coordination function, to ensure the efficient and most cost-effective dispatch of the generation fleet.

Seiler is on the board of directors of ReliabilityFirst. ReliabilityFirst is one of the eight Federal Energy Regulatory Commission-approved Regional Entities responsible for ensuring the reliability of the North American Bulk-Power System Fund. He is also on the board of PJM Environmental Information Services, Inc. In addition, Seiler is an instructor for the Mayfly Project, which is a national organization that uses fly fishing as a catalyst to mentor and support children in foster care and introduce them to their local water ecosystems, with a hope that connecting them to a rewarding hobby will provide an opportunity for foster children to have fun, build confidence and develop a meaningful connection.

Prior to joining PJM, Seiler was employed by Metropolitan Edison Company/GPU Energy for nearly 14 years. He held the positions of operations manager, transmission engineering manager, relay protection and control engineer, and substation/transmission construction and maintenance engineer.

Seiler earned a Bachelor of Science in electrical engineering from the Pennsylvania State University and a Master of Business Administration from Lebanon Valley College.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes over 84,236 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of \$2.8 billion to \$3.1 billion.



ATTACHMENT B



Initial Comments of PJM Interconnection, L.L.C.

*Building for the Future through Electric Regional Transmission Planning
and Cost Allocation and Generator Interconnection*

Docket No. RM21-17-000

August 17, 2022

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Building for the Future Through)
Electric Regional Transmission)
Planning and Cost Allocation and)
Generator Interconnection)**

Docket No. RM21-17-000

INITIAL COMMENTS OF PJM INTERCONNECTION, L.L.C.

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**UNITED STATES OF AMERICA
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**Building for the Future Through
Electric Regional Transmission
Planning and Cost Allocation and
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Docket No. RM21-17-000

INITIAL COMMENTS OF PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. (“PJM”)¹ submits the following initial comments (“Comments”) in response to the Notice of Proposed Rulemaking (“NOPR”) issued by the Federal Energy Regulatory (“Commission”) on April 21, 2022 in the above-captioned docket.² PJM appreciates the opportunity to comment on the vast number of issues and questions raised in the NOPR.

I. EXECUTIVE SUMMARY

Over the past decade, increasing focus by federal and state governments, corporations and other organizations regarding climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. PJM agrees with the fundamental premises underlying the NOPR, *i.e.*, that facilitation of transmission investment will help enhance reliability, reduce power costs, and address our nation’s changing resource mix. PJM also agrees that a longer-term, forward-looking approach to transmission planning can help to

¹ PJM is an independent regional transmission organization (“RTO”) that coordinates the movement of wholesale electricity for systems that serve approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM’s more than 1,040 members/customers include power generators, transmission owners, electricity distributors, power marketers and large consumers. PJM operates one of the world’s largest centrally dispatched grids. PJM dispatches approximately 185,000 megawatts (“MW”) of generating capacity over more than 85,000 miles of transmission lines.

² *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking*, 179 FERC ¶ 61,028, 87 Fed. Reg. 26,504 (May 4, 2022) (“NOPR” or “LTRTP NOPR”).

achieve these goals. In addition, PJM strongly supports the need to allow the present short-term reliability and market efficiency planning processes³ to proceed in their current form so as to ensure that the vital day-to-day work of maintaining a reliable and efficient grid can continue.⁴ Accordingly, and for the reasons discussed more fully below, PJM generally supports the Commission’s proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by “changes in the resource mix and demand” (referred to herein as “Long-Term Regional Transmission Planning”).⁵

That said, there are a number of key issues that PJM believes the Commission must bear in mind as it develops a Final Rule implementing Long-Term Regional Transmission Planning processes, including:

- **The Final Rule Should Address Enhanced Reliability:** As PJM explained in its initial⁶ and reply⁷ comments addressing the Advance Notice of Proposed Rulemaking in this

³ PJM’s currently-effective Regional Transmission Expansion Plan (“RTEP”) process provides for the identification of transmission system enhancements or expansions to address reliability, operational performance, economic and public policy needs based on analyses that include: (i) RTEP planning criteria such as interconnection planning procedures, NERC Reliability Standards, Regional Entity reliability principles and standards and individual transmission owner FERC Form No. 715 planning criteria (referred to herein as reliability planning) and (ii) the analysis of the economic efficiency of power delivery driven by PJM’s energy and capacity markets, that determine the need for RTEP market efficiency upgrades (referred to herein as market efficiency planning).

⁴ For purposes of these Comments, PJM focuses on three different planning horizons within the planning process: (i) the present five-year forward planning horizon to address short-term reliability and market efficiency needs, which PJM describes herein as “short-term planning;” (ii) the six- to 15-year analysis that PJM undertakes today to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development, which PJM describes herein as “intermediate-term planning;” and (iii) the NOPR’s proposed 20-year long-term planning process, which PJM describes herein as “Long-Term Regional Transmission Planning” (the term the Commission uses in the NOPR). In the future, these three planning horizons will inform each other, just as the existing short-term planning and intermediate-term planning processes do today.

⁵ See NOPR at P 45.

⁶ *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000 (“PJM Initial ANOPR Comments” or “PJM’s Initial ANOPR Comments”) (Oct. 12, 2021).

⁷ *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Reply Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000 (“PJM ANOPR Reply Comments” or “PJM’s ANOPR Reply Comments”) (Nov. 30, 2021).

docket,⁸ any endeavor to tackle the transmission needs of the electric grid of the future would be incomplete without factoring resilience into revisions to intermediate-term and Long-Term Regional Transmission Planning processes.⁹ In these comments, PJM refers to this concept as “Enhanced Reliability,”¹⁰ and proposes that Enhanced Reliability be addressed holistically with the Commission’s two other recently-issued Notices of Proposed Rulemaking.¹¹ In particular, PJM proposes below a comprehensive proposal that would: (i) maintain existing short-term planning processes to address reliability and market efficiency needs, consistent with the Commission’s commitment in the NOPR;¹² (ii) include Enhanced Reliability as a specific factor to be considered in both the intermediate-term and the Long-Term Regional Transmission Planning processes; and (iii) harmonize the Commission’s various Transmission Planning NOPRs so as to avoid the topic of Enhanced Reliability planning being “piecemealed” as between new proposed North American Electric Reliability Corporation (“NERC”) processes and Long-Term Regional Transmission Planning processes as it relates to intermediate-term planning (between the five-year and the planning horizon associated with the Long-Term Regional Transmission Planning process¹³),¹⁴

- **The Final Rule Should Avoid a Litigious, Elongated and Disparate Compliance Process:** PJM believes that the Commission should consider “lessons learned” when directing any compliance process arising out of the Final Rule. As the Commission is aware, the Order

⁸ *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advance Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021) (“ANOPR”).

⁹ See PJM Initial ANOPR Comments at 27-41; PJM ANOPR Reply Comments at 7-10.

¹⁰ As set forth below, PJM proposes to define “Enhanced Reliability” as “[t]he ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.” PJM uses this term rather than the term “resilience,” given concerns raised by some regarding the use of the term “resilience” and its being confused with a prior Department of Energy proposal, long since rejected by the Commission.

¹¹ See *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (2022) (referred to herein as the “Extreme Weather NOPR”); *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, 179 FERC ¶ 61,196 (2022) (referred to herein as the “Informational Reports NOPR”). Together with the LTRTP NOPR that is the subject of these comments, the Extreme Weather NOPR and the Informational Reports NOPR are collectively referred to as the “Transmission Planning NOPRs.”

¹² See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

¹³ As set forth in Section III.A.2.a, below, PJM recommends that the Commission adopt a 15-year planning horizon for the Long-Term Regional Transmission Planning process.

¹⁴ See Section II.A, *infra*.

No. 1000¹⁵ compliance process was extremely resource-intensive and litigious, which, in turn, delayed implementation of Order No. 1000 reforms across the country. PJM therefore outlines below a proposed process that should govern any compliance requirements associated with a Final Rule in this docket;¹⁶

- **The Final Rule Should Include a Uniform, Nationwide Decision Regarding the Federal Right of First Refusal:** As set forth below, PJM believes that because the Commission eliminated the federal right of first refusal on a nationwide basis in Order No. 1000, the decision about whether to reinstate the federal right of first refusal must be made by the Commission on a nationwide basis, and not left to a patchwork of regional decisions that are influenced more by the minutiae of individual voting structures than sound consideration of what clearly is a national policy issue. The Commission should not avoid its responsibility to make a policy call on this topic so as to avoid a series of piecemeal policies that are discriminatory on their face, could erode Regional Transmission Organization (“RTO”) membership stability, and encourage “RTO shopping” among transmission owners.

Additionally, PJM provides the Commission with objective data as to its experiences with the competitive solicitation process in effect since as early as 2013. Although PJM is not taking a position on the ultimate policy decision concerning reinstatement of the federal right of first refusal, the data PJM provides for the record demonstrates that even when nonincumbent transmission developers have had the opportunity to submit project proposals through a PJM competitive window process, in almost all instances, the nonincumbents’ proposals were not found to be the more efficient or cost effective solution.

Based on this data and PJM’s extensive experience and substantial efforts associated with implementing Order No. 1000 competitive solicitations (including the most recent solicitation for projects to support the state of New Jersey’s use of PJM’s State Agreement Approach process for development of offshore wind¹⁷), PJM recommends that if the Commission decides not to reinstate the federal right of first refusal, the Commission should consider a more narrow subset of unique transmission projects for which the competitive solicitation process might be appropriate.

As to the Commission’s proposal regarding a conditional federal right of first refusal for certain jointly-owned transmission facilities, PJM requests that the Commission: (a) reconsider whether joint ownership arrangements, although beneficial, should become a new *condition precedent* to the reinstatement of the federal right of first refusal; and

¹⁵ *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh’g*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh’g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff’d sub nom.*, *S.C. Pub. Serv. Auth. v. F.E.R.C.*, 762 F.3d 41 (D.C. Cir. 2014).

¹⁶ See Section II.B, *infra*.

¹⁷ See Section II.C.2.d, *infra*.

(b) decline to put transmission providers in the position of evaluating the financial structure of any joint ownership proposal.¹⁸

- **Equitable Treatment Between RTO/Independent System Operator (“ISO”) and Non-RTO/ISO Regions:** Changes to the resource mix and demand are not limited to RTO/ISO regions. The Commission should ensure that its proposed reforms are implemented in a manner that does not create disincentives for transmission owner participation in RTOs/ISOs. PJM identifies herein those areas where the implementation of any planning reforms should be consistent across the nation, and those areas where reforms would be more appropriately addressed by the respective regions.

Additionally, while PJM generally supports the proposed Long-Term Regional Transmission Planning process as an add-on to existing short- and intermediate-term reliability and market efficiency planning processes,¹⁹ PJM believes that there are several elements of the proposed Long-Term Regional Transmission Planning process that are unworkable or inappropriate for the PJM Region and need to be modified before they are incorporated into a Final Rule. Accordingly, PJM provides comments below on each element of the Long-Term Regional Transmission Planning process proposal, setting forth the areas where PJM agrees with the Commission’s proposal, as well as areas where PJM recommends that the Commission make modifications, summarized as follows:

- **Length of Planning Horizon for Scenario Development and Scenario Assessment:** PJM believes a 15-year planning horizon, as compared to a 20-year planning horizon, strikes a more appropriate balance between the uncertainty inherent to long-term transmission planning and the need to allow for sufficient time to identify, plan, and obtain siting and permitting approval, and to construct regional transmission facilities to meet long-term regional transmission needs. Accordingly, PJM recommends that the Commission consider a 15-year planning horizon for Long-Term Scenario²⁰ development. As described below, PJM supports the Commission’s proposal that transmission providers assess the Long-Term Scenarios used in the Long-Term Regional Transmission Planning process

¹⁸ See Section II.C, *infra*.

¹⁹ See Section III.A.1, *infra*.

²⁰ The Commission explains the term “Long-Term Scenarios” is meant to “describe a tool to identify transmission needs driven by changes in the resource mix and demand, and enable the evaluation of transmission facilities to meet such needs, across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon.” NOPR at P 69, n.129.

every three years, but requests that the Commission confirm that the three-year assessments are to proceed in a serial, non-overlapping fashion, meaning that the assessment and development of the Long-Term Scenarios be completed *before* the next three-year assessment and development begins.²¹

- **Factors to be Used to Develop Long-Term Scenarios:** PJM generally supports the seven specific categories of factors that the Commission proposes to require transmission providers to consider as they seek to identify transmission needs driven by changes in the resource mix and demand (“Factors”).²² However, PJM believes the Commission should modify its list of seven Factors by: (i) directing transmission providers to include Enhanced Reliability Planning and Interregional Transfer Capability as two additional factors to consider when developing the Long-Term Scenarios; (ii) directing the consideration of customer surveys and documentation of customer-identified needs, as well as probabilistic planning as part of the Long-Term Regional Transmission Planning process; (iii) declining to impose prescriptive requirements regarding the development of factors that would complicate region-specific efforts to promote more efficient and cost-effective regional transmission planning and development; (iv) clarifying that the burden to ensure that a transmission planner is aware of any local laws, local regulations and/or local goals proposed to be factored into Long-Term Scenario planning is on the states, stakeholders, or local regulators, not on the transmission planner; and (v) clarifying, with respect to the incorporation of economic analyses of potential generation capacity retirements, how transmission providers should engage in such analyses while balancing market participant confidential information and transparency.²³
- **State and Stakeholder Input Regarding Factor and Long-Term Scenario Development:** PJM supports greater engagement by states and stakeholders to provide input regarding the development of Long-Term Scenarios. In fact, PJM already has standing committees in place that would be the appropriate place for such discussions.²⁴
- **Use of Multiple Long-Term Scenarios:** PJM generally supports the Commission’s proposal to require transmission providers to develop an array of future Long-Term Scenarios, but believes that the Commission should allow individual transmission

²¹ See Section III.A.2.a, *infra*.

²² Specifically, the Commission proposes that transmission providers incorporate the following seven categories of Factors into the development of Long-Term Scenarios: “(1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.” NOPR at P 104 (footnotes omitted).

²³ See Section III.A.b, *infra*.

²⁴ *Id.*

providers flexibility to develop more or fewer than four Long-Term Scenarios.²⁵

- **Use of “Best Available Data”**: PJM supports the proposal that transmission providers be required to use best available data inputs in the development of Long-Term Scenarios. Indeed, PJM’s RTEP short- and intermediate-term analyses currently incorporate the latest and best available information regarding load forecasts, generating resources, transmission topology, demand resources and bilateral transactions. Additionally, PJM would be supportive of the Commission holding forums to discuss best practices for the development of additional data sources.²⁶
- **Geographic Zones**: PJM does not support the Commission’s proposal to require transmission providers to identify geographic zones with the potential for large amounts of new generation, nor does PJM believe that transmission providers should be responsible for assessing whether there is evidence that generation developers have demonstrated commercial interest in developing generation within a geographic zone. That said, PJM believes an alternative, more case-specific flexible approach that builds on and is better synchronized with the transmission provider’s interconnection queue process and market developments, and accommodates topologies as diverse as those in PJM, may be a better alternate solution for the PJM Region.²⁷
- **Aligning Interconnection Processes with Long-Term Regional Transmission Planning Processes**: PJM does not support the Commission’s proposal to align the interconnection and the Long-Term Regional Transmission Planning processes by requiring that transmission needs identified through the interconnection queue drive regional transmission planning decisions. Rather, PJM believes a more targeted, case-specific approach to aligning transmission build-outs associated with multiple interconnection requests at a common location on the grid, as well as the reforms proposed in PJM’s Interconnection Process Reform Filing,²⁸ will better resolve the concerns the Commission is attempting to address with this proposal.²⁹
- **Evaluation of Benefits Associated with Transmission Facilities to Address Long-Term Needs Driven by Changes in the Resource Mix and Demand**: PJM supports the Commission’s proposal to require transmission providers to identify and quantify benefits associated with transmission facilities that address needs driven by changes in the resource mix and electricity demand. However, PJM believes that there is significant overlap among

²⁵ See Section III.A.c, *infra*.

²⁶ See Section III.A.d, *infra*.

²⁷ See Section III.A.e, *infra*.

²⁸ *PJM Interconnection, L.L.C.*, Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (June 14, 2022) (“Interconnection Process Reform Filing”). In the Interconnection Process Reform Filing, PJM proposes revisions to significantly improve the process by which new and upgraded generation resources connect to the grid.

²⁹ See Section III.B.1, *infra*.

the 12 categories of benefits that the Commission has proposed, and therefore proposes instead five consolidated categories of benefits that PJM would consider specific to the PJM Region, as well as a core subset of benefits to be considered nationwide.³⁰

- **Project Selection**: PJM believes that the Commission’s proposal to require transmission providers to specify the criteria by which they will identify and evaluate transmission facilities for potential selection pursuant to the Long-Term Regional Transmission Planning process is unclear, premature and inconsistent with other aspects of the NOPR. PJM addresses the ambiguities associated with the project section criteria below. As to the premature nature of the selection criteria proposal, PJM recommends that rather than requiring transmission providers to propose the project selection criteria and cost allocation processes for projects that may potentially be selected to be included in the RTEP in their initial compliance filings, the Commission should provide for a phased-in approach that directs transmission providers to first develop their processes for developing and evaluating Long-Term Scenarios. PJM believes that only after transmission providers have had the opportunity to gain experience with Long-Term Scenario development and evaluations should they be required to propose selection criteria and cost allocation methodologies for inclusion in their tariffs. Finally, PJM submits several recommendations for the Commission’s consideration in order to address the conflict between the selection criteria proposal and the Commission’s goals stated elsewhere in the NOPR that the Long-Term Regional Transmission Planning process is: (i) an add-on to the existing short-term planning processes and (ii) designed to better inform, without changing, those short-term processes, and in particular those related to reliability and market efficiency planning.³¹
- **Consideration of Dynamic Line Ratings (“DLR”) and Advance Power Flow Control (“APFC”) Devices**: Although DLR and APFC devices are tools that can be utilized, in select instances, to inform short-term horizon market efficiency planning solutions,³² they are not interchangeable substitutes for the need to develop new transmission infrastructure to address long-term transmission needs focused on reliability. The NOPR goes too far in appearing to signal that DLR and APFC devices are acceptable solutions that could simply obviate the need to address a demonstrated reliability need either in the short, intermediate or long-term.³³ PJM cautions the Commission to avoid any inference that DLR and APFC devices can serve as long-term substitute solutions to meet system reliability needs. Failure to do so could compromise system reliability, complicate the siting process, and encourage public opposition to the need for new transmission to meet reliability and market efficiency needs.

³⁰ See Section III.B.2, *infra*.

³¹ See Section III.B.3, *infra*.

³² PJM outlines the promising potential for deployment of DLR technologies to address operational issues both in these Comments and its Comments in Docket No. AD22-5-000. See *Implementation of Dynamic Line Ratings*, Motion for Leave to Comment and Comments of PJM Interconnection, L.L.C., Docket No. AD22-5-000 (May 9, 2022).

³³ See Section III.B.4, *infra*.

In addition to the above, PJM comments below on several other proposals set forth in the NOPR, including:

- **Cost Allocation for Facilities Selected through the Long-Term Regional Transmission Planning Process:** PJM’s established cost allocation methodologies for reliability-based projects, market efficiency projects, public policy projects addressing state-identified needs, and multi-driver projects were developed after many years of discussion and litigation involving stakeholders and states in the PJM Region. PJM requests that the Commission clarify in any Final Rule that although the states are free to work with transmission owners, PJM and stakeholders on any *new* alternative cost allocation methods, the NOPR was not intending to force *de novo* reconsideration of existing settled cost allocation methods. Further, absent future agreement by all affected states, PJM believes that its existing *ex ante* cost allocation methodologies should be applied to facilities pursuant to the Long-Term Regional Transmission Planning process.³⁴
- **Construction-Work-In-Progress:** PJM does not take a position on the Commission’s proposal to prevent transmission owners from taking advantage of the construction-work-in-progress (“CWIP”) incentive for facilities developed pursuant to the Long-Term Regional Transmission Planning process. However, PJM cautions the Commission that its particular proposal as to when CWIP is available and when it is not may have some unintended gaming consequences that might complicate the construction of such facilities.³⁵
- **“Right-Sizing” Replacement Transmission Facilities:** PJM supports the concept that transmission providers should be required to evaluate whether transmission facilities operating at or above 230 kV can be “right-sized” to address regional transmission needs identified in the Long-Term Regional Transmission Planning process. Additionally, PJM also encourages the Commission to explore the potential benefits of extending application of “right-sizing” to include transmission facilities at or above 100 kV to be assessed for a rebuild upgrade to a higher voltage level as part of the Long-Term Regional Transmission Planning process, provided it does not delay the planning of short-term reliability needs and customer service.³⁶
- **Interregional Coordination:** PJM believes that reforms specific to interregional coordination should not be limited to sharing information or identifying interregional transmission facilities to address needs identified specific to the Long-Term Regional Transmission Planning process. PJM sets forth an alternative approach that would provide a clear path for development of interregional transfer capability methodologies and other

³⁴ See Section III.C, *infra*.

³⁵ See Section III.D, *infra*.

³⁶ See Section III.E, *infra*.

measures to strengthen interregional coordination.³⁷

- **The Commission Underestimates the Cost and Time Commitments Associated with Implementation of the Proposed Long-Term Regional Transmission Planning Process:** PJM believes that the Commission has greatly underestimated the time, effort, and financial resources that individual RTOs like PJM will have to expend in order to comply with any Final Rule in this docket. PJM anticipates that it will have to create a new department within its Transmission Planning group whose principle function will be to develop the Long-Term Scenario planning processes proposed in the NOPR as well as undertake related planning activities. To that end, although PJM believes that the Commission's proposed eight-month period for transmission providers to submit compliance filings in this docket is reasonable, PJM urges that Commission to thereafter allow for a reasonable amount of time for transmission planners to develop the tools and hire the employees they will need to implement the Final Rule.³⁸

Finally, to aid the Commission, PJM proposes specific language additions or edits to the proposed Final Rule to implement its proposed revisions where appropriate.³⁹

PJM has held over eight stakeholder meetings and participated in 11 meetings with state commissioners⁴⁰ to discuss the issues raised in this proceeding, as well as the recommendations set forth in PJM's Comments. PJM is appreciative of that input, as it has led to a more deliberative discussion among the PJM community on these issues. PJM stands ready to aid the Commission as it considers the important issues set forth in the NOPR.

³⁷ See Section III.F, *infra*.

³⁸ See Section III.G, *infra*.

³⁹ PJM provides rule changes specific to several issues raised in the NOPR in various sections of these comments. For the Commission's convenience, PJM also includes in Appendix A to these comments a consolidated set of PJM's proposed revisions to the proposed Final Rule.

⁴⁰ PJM has met with state commissioners that are participating on the Joint Federal-State Task Force on Electric Transmission between the Commission and the National Association of Regulatory Utility Commissioners ("NARUC"). PJM has also met with the Independent State Agencies Committee ("ISAC") and the Organization of PJM States, Inc. ("OPSI") to discuss transmission reforms.

II. ELEMENTS THAT MUST BE ADDRESSED IN THE FINAL RULE

A. Enhanced Reliability Planning Should Be a Specific Factor to be Addressed in any Long-Term Scenario-Based Planning Process

In its ANOPR comments, PJM urged consideration of future reliability needs to be addressed through the planning process.⁴¹ Given the structure of the LTRTP NOPR and its preservation of continued reliability planning as is currently undertaken by PJM and other transmission providers,⁴² along with the Commission’s action addressing portions of the reliability issue in two other recently-issued Notices of Proposed Rulemaking,⁴³ PJM sets forth below a comprehensive proposal which would:

- maintain the existing short-term (5-year) planning process as applied to reliability and market efficiency projects, consistent with the LTRTP NOPR;⁴⁴
- include Enhanced Reliability⁴⁵ (as previously referred to as resilience)⁴⁶ as a specific Factor⁴⁷ to include in the planning horizon required as part of the Long-Term Regional Transmission Planning process;⁴⁸ and
- harmonize the Commission’s various Transmission Planning NOPRs so as to avoid the topic of Enhanced Reliability planning being “piecemealed” as between new proposed NERC processes and Long-Term Regional Transmission Planning processes as it relates to planning in the intermediate-term (between the five-year and the planning horizon

⁴¹ See PJM Initial ANOPR Comments at 41-46; PJM ANOPR Reply Comments at 5-15.

⁴² See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

⁴³ See n.11, *supra*.

⁴⁴ NOPR at PP 3, 72, 89.

⁴⁵ As set forth below, PJM proposes to define “Enhanced Reliability” as “[t]he ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.”

⁴⁶ See PJM Initial ANOPR Comments at 27-41; PJM ANOPR Reply Comments at 5.

⁴⁷ See Section III.A.2.b, *infra*.

⁴⁸ As set forth in Section III.A.2.a, below, PJM recommends that the Commission adopt a 15-year planning horizon for the Long-Term Regional Transmission Planning process.

required as part of the Long-Term Regional Transmission planning process).

The specifics of each component of this proposal, which spans the various Transmission Planning NOPRs, is outlined below.

1. PJM Requests that the Commission Reinforce the Need for Short-Term 5-Year Processes to be Able to Respond Quickly to Address Imminent Reliability Violations and Short-Term Market Efficiency Needs

PJM understands that the Commission proposes to establish the new Long-Term Regional Transmission Planning process as an add-on, supplemental process, that is not intended to modify the existing short-term reliability and market efficiency processes presently in existence.⁴⁹ PJM strongly supports that approach to maintain the current portions of the planning process focused on promptly addressing identified reliability violations and short-term market efficiency issues identified within a five-year period. Being able to respond quickly to address these imminent needs is critical to ensuring the reliability and efficiency of the power grid. Grid topology can change dramatically in the short-term as a result of:

- major load additions or losses as large customers such as data centers are expanded within a zone or industrial customers close facilities and leave the zone;
- generation retirements that are announced on short notice to PJM as a result of a particular unit failing to clear a capacity auction or facing other external events that precipitate closure; and
- reliability violations that are identified in the short term due to equipment failures, enhanced CIP-014 requirements, and other needs to reinforce the system.

⁴⁹ See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

For these reasons, PJM appreciates the Commissions affirmation of the need to maintain the current short-term reliability and market efficiency planning processes, and urges the Commission to reaffirm in the Final Rule its intention to not disturb the short-term five-year planning that addresses reliability and market efficiency. Although the long-term planning horizon that the Commission contemplates as part of the Long-Term Regional Transmission Planning process can and will certainly *inform* the short-term process, it is imperative that the short-term five-year-out process continue to be able to respond to short-term needs quickly and nimbly.

2. PJM Requests that the Commission Bring Enhanced Reliability Into the Long-Term Regional Transmission Planning Process

While not disturbing the short-term process to respond to imminent reliability violations and market efficiency needs, PJM believes that Enhanced Reliability planning (which PJM has referred to in the past as “resilience”) should be added as a specific Factor to be included in the enumerated Factors set forth in the NOPR for consideration in the proposed Long-Term Regional Transmission Planning process.⁵⁰ Reliability and market efficiency are clearly factors that need to be considered in the Long-Term Regional Transmission Planning process so as to ensure that the long-term projections account for the need to ensure the integrity of the grid. PJM therefore urges the Commission to include Enhanced Reliability as a Factor to be considered in the Long-Term Regional Transmission Planning process. PJM’s specific proposed changes to the proposed Rule are set forth below.

⁵⁰ See NOPR at P 104.

3. PJM Requests that the Commission Harmonize and Provide Clear Direction on Enhanced Reliability Measures Which Span the Various Transmission Planning NOPRs

As indicated above, the Commission recently issued two other Notices of Proposed Rulemaking addressing transmission-planning related issues.⁵¹ When the various Transmission Planning NOPRs are read in totality, it is unclear what the Commission is directing regarding the consideration of Enhanced Reliability in the intermediate-term, *i.e.*, those planning actions that look beyond the short term planning horizon (0 to five years), but consist of a planning horizon that stops short of the LTRTP Planning Horizon proposed in the LTRTP NOPR. For example, the Commission has proposed to assign a narrow portion of Enhanced Reliability planning, namely addressing hot and cold temperatures, to NERC and its stakeholder process.⁵² Other issues such as storm hardening, de-listing critical CIP-014 facilities, and gas/electric coordinated planning, each of which PJM addressed in its ANOPR comments,⁵³ are mentioned briefly in the LTRTP NOPR or, in other cases, not at all.

The Commission needs to underscore the importance of Enhanced Reliability planning and provide clear direction on what it wishes to see in this area in the planning process. Rather than a piecemeal approach to this issue, with portions going to NERC and other portions not addressed at all, PJM believes it would be helpful for the Commission to address the need for Enhanced Reliability planning in the intermediate-term and proposed Long-Term Regional Transmission Planning processes. Elements of that process would include: (i) a specific transmission driver that would allow for development of a more robust and resilient grid that goes beyond the technical

⁵¹ See n.11, *supra*.

⁵² See Extreme Weather NOPR at P 6.

⁵³ See PJM Initial ANOPR Comments at 27-40; PJM Reply ANOPR Comments at 9.

strictures of compliance with NERC standards; (ii) a defined benefit metric associated with these intermediate- and long-term upgrades; and (iii) as noted above, a Factor to be considered in Long-Term Scenario planning.⁵⁴

Clear direction from the Commission on these elements as part of this nationwide rulemaking would help to ensure that transmission planning over the intermediate- and long-term allows for the grid to not just remain in technical compliance with current NERC standards, but is built to lower the impact of more extreme events and occurrences, some of which are simply beyond the scope of NERC standards or even NERC authority. Unfortunately, a comprehensive approach to addressing these issues is not evident in the suite of Transmission Planning NOPRs that have been issued to date.

Although PJM recognizes that arguably it could revise its Amended and Restated Operating Agreement (“Operating Agreement”) to include these additional Enhanced Reliability drivers on its own via Federal Power Act (“FPA”) section 205, the Transmission Planning NOPRs, both singularly and collectively, adopt a *nationwide* set of minimum planning standards. It would be inappropriate in PJM’s view to simply leave these important reliability issues to individual regions to address on their own, given that both the Eastern and Western Interconnections are large, interconnected machines where reliability concerns in one part of the Interconnection can potentially affect the rest of the Interconnection.

For this reason, PJM believes that to avoid different approaches to these nationwide issues, a common Enhanced Reliability planning driver should be crafted by the Commission to cover

⁵⁴ See Section III.A.2.b, *infra*.

planning in the period beyond the short-term five-year planning horizon and addressed either in the LTRTP NOPR or the Extreme Weather NOPR.

4. PJM Stresses the Need for a Holistic Intermediate- and Long-Range Approach to the Enhanced Reliability Issue Across the Various Transmission Planning NOPRs

PJM wishes to focus on a key part of transmission planning that is barely addressed in the LTRTP NOPR and subdivided into parts in some of the other recently-issued Transmission Planning NOPRs. Throughout this proceeding, and dating back to proceedings before the Commission in Docket No. AD18-7-000 (the “RTO/ISO Resilience Proceeding”), PJM has consistently asserted that a holistic approach to these reliability issues needs to include specific direction and support, *on a nationwide basis*, for steps to ensure continued and robust reliability of the electric grid. PJM outlines once again the history of this issue and proposes herein specific solutions that it would urge the Commission to address in its Final Rule to help ensure that this issues is not addressed on a piecemeal basis in various other proceedings.⁵⁵

On January 8, 2018, the Commission initiated the RTO/ISO Resilience Proceeding to specifically evaluate the resilience of the bulk power system in the regions operated by RTOs and ISOs.⁵⁶ The Commission explained, among other things, “*that a proper evaluation of grid resilience should not be limited to [a] single issue, and should instead encompass a broader consideration of resilience issues, including wholesale electric market rules, planning and*

⁵⁵ PJM refers to the variety of components associated with this important planning element as a request for a planning driver to ensure “enhanced reliability” given the many external events that will continue to impact system reliability into the future. Although PJM and the Commission previously couched this request in terms of “resilience,” as noted below, the requested transmission planning driver includes more than just the ability to withstand extreme events (as is commonly thought of with use of the term resilience), but also includes such key elements such as planning for cybersecurity threats, “de-listing” critical CIP-014 facilities, and examination of gas/electric interdependencies.

⁵⁶ *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) (“RTO/ISO Resilience Order”).

*coordination, and NERC standards.”*⁵⁷ To this point, the Commission stated that “*the efforts of RTOs and ISOs on grid resilience encompass a range of activities, including wholesale electric market design, transmission planning, mandatory reliability standards, emergency action plan development, inventory management, and routine system maintenance.*”⁵⁸

In response to the Commission’s RTO/ISO Resilience Order, PJM submitted comments that: (i) outlined the considerable steps PJM and its stakeholders had undertaken, or were actively underway, to enhance the resilience of the portion of the Bulk Electric System (“BES”) operated by PJM; and (ii) detailed specific steps the Commission could undertake to enhance overall resilience of the BES, not just in the PJM Region but potentially across the nation.⁵⁹ PJM explained that “resilience is not only about high-impact, low-frequency events” but “[r]ather, 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.”⁶⁰ Importantly, PJM emphasized that “[p]rudent 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.*”⁶¹

⁵⁷ RTO/ISO Resilience Order at P 19 (emphasis added).

⁵⁸ *Id.*

⁵⁹ See *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Comments and Responses of PJM Interconnection, L.L.C., Docket No. AD18-7-000 (Mar. 9, 2018) (“2018 Resilience Comments”). PJM includes as Appendix B to these comments the Executive Summary from its 2018 Resilience Comments, which outlines the specific proposals PJM offered in that proceeding.

⁶⁰ 2018 Resilience Comments at 4.

⁶¹ *Id.* at 5 (emphasis added).

The Commission terminated the RTO/ISO Resilience proceeding without further action on February 18, 2021.⁶² In doing so, the Commission stated that while it was not taking any particular action based on the record, ***“the resilience and reliability of the bulk power system must—and will—remain one of the Commission’s paramount responsibilities and concerns.”***⁶³ Similarly, Commissioners Christie and Clements in their concurrence stated that ***“[t]he issues attendant to grid resilience and reliability that this particular proceeding raised are compelling and must command this Commission’s future attention.”***⁶⁴

5. PJM’s Enhanced Reliability Planning Proposal

Despite the Commission’s statements in the RTO/ISO Resilience Proceeding, neither the LTRTP NOPR nor any of the companion Transmission Planning NOPRs address the important topic of Enhanced Reliability in a comprehensive way. Instead, the Commission appears to be exploring the use of a piecemeal approach to the topic of resilience, through its recent issuance of three separate Transmission Planning NOPRs.

PJM strongly urges reconsideration of this approach as it pertains to planning in the intermediate- and long-term (*i.e.*, beyond the short-term, five-year planning horizon). Attempting to address a complex and interrelated issue like Enhanced Reliability by sending specific segments in isolation to NERC, or focusing on specific narrow elements like “extreme hot” or “extreme cold” weather, will invariably fail to produce comprehensive reforms that are interconnection-wide in scope and needed to meet the reliability challenges that face the industry in the future. PJM believes that the Commission may be missing an important opportunity to enhance the

⁶² *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,111 (2021) (“Order Terminating Resilience Proceeding”).

⁶³ *Id.* at P 4.

⁶⁴ *Id.*, Christie and Clements Concurring opinion at P 1 (emphasis added).

existing reliability and market efficiency processes on a discrete set of issues that are beyond any one region to solve.

To date, the Commission has been reluctant to embrace the term “resilience” as a planning driver. Whether one labels the initiative under the rubric of “resilience” or “Enhanced Reliability,” the goal is the same, namely to ensure, as PJM set forth in its 2018 Comments:

The ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.⁶⁵

PJM explained that its proposed definition varied modestly from the Commission’s then-proposed definition in order to ensure that the definition was realistic, and the corresponding requirements on transmission planners were achievable.⁶⁶

PJM believes that its proposed Enhanced Reliability goal is appropriate today, and (i) has commonality of intent with the Commission’s previously-proposed definition; (ii) accurately reflects what transmission planners are capable of doing to protect the BES from vulnerabilities and threats; and (iii) does not subject transmission planners to additional liabilities, or unreasonable new duties or standards of care. PJM further believes that the Commission setting forth a clear goal applicable to *all regions* is the first step to building on each region’s reliability authority to ensure a more comprehensive interconnection-wide approach to this vital issue.

Additionally, the Commission should propose a framework by which regions can develop resilience-based industry planning “drivers” to advance resilience planning, and require all regions to develop resilience planning criteria that would trigger actionable grid expansion in the

⁶⁵ 2018 Resilience Comments at 10.

⁶⁶ *Id.*

intermediate- and long-range planning processes. These criteria might include resilience-specific elements, such as: (i) storm hardening of facilities and responsiveness plans, (ii) long-term restoration planning for loss of critical infrastructure, (iii) focusing on potential “sensitive” areas of the system similar to PJM’s Critical Substation Planning Analysis (as approved by PJM stakeholders in 2021),⁶⁷ and (iv) planning to proactively prevent introduction of new CIP-014 facilities, and “de-listing” already identified CIP-014 facilities.⁶⁸ These criteria should also include elements related to gas/electric planning coordination to reduce vulnerabilities shared by both sectors, and should ensure consistency in Long-Term Scenario inputs including standard thresholds for event probability of occurrence and perhaps maximum level of load loss for those planning Long-Term Scenarios across the Eastern Interconnection. PJM recommends that the Commission require these drivers to be codified in transmission providers’ tariffs, both for RTO/ISO regions and non-RTO/ISO regions, as resilience events (*e.g.*, extreme weather) can often span both, as observed in February 2021.

6. PJM Proposes the Following Revisions Related to Enhanced Reliability Planning for Incorporation in the Final Rule

PJM proposes four specific changes to the text contemplated by the NOPR. First, PJM proposes that the Final Rule make clear that Enhanced Reliability is a factor to be considered in the new Long-Term Regional Transmission Planning process:

When developing Long-Term Scenarios, the Transmission Providers in each transmission planning region must: (1) use a transmission planning horizon no less

⁶⁷ PJM, *Manual 14B: PJM Region Transmission Planning Process*, § 2.9 (rev. 51, Dec. 15, 2021).

⁶⁸ NERC developed reliability standard CIP-014-2 to identify and protect transmission stations and substations, and their associated primary control centers that, if rendered inoperable or damaged by physical attack, could result in instability, uncontrolled separation, or cascading. The standard requires transmission owners to conduct assessments to identify such critical facilities. Currently, however, no industry standard or uniform planning driver exists by which transmission providers can plan the regional transmission system specifically in order to mitigate CIP-014 facilities. Transmission providers should be required to assess the impact of the loss of such critical facilities, including facilities that the transmission provider identifies as critical on a regional basis based upon reliability principles.

than ~~15~~ 20 years into the future; (2) reassess and revise Long-Term Scenarios including to reassess whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revise their Long-Term Scenarios as needed to reflect updated data inputs and factors at least every three years, and complete the development of Long-Term Scenarios within three years, before the next three-year assessment commences; (3) incorporate, at a minimum, the ~~seven~~ nine categories of factors identified in Order No. [final rule] that may drive transmission needs driven by changes in the resource mix and demand; (4) develop a plausible and diverse set of at least four Long-Term Scenarios; (5) use “best available data” (as defined in Order No. [final rule]) in developing Long-Term Scenarios; and (6) consider whether to identify geographic zones with the potential for development of large amounts of new generation.⁶⁹

Second, since the NOPR proposes that the Final Rule incorporate in Attachment K of the Commission’s *pro forma* Open Access Transmission Tariff (“OATT”) the Factors set forth in the NOPR by reference, PJM would propose further specification in the list of Factors found in NOPR Paragraph 104 by adding the following proposed additional Factor:

*(8) identified needs to enhance the reliability of the grid including, but not limited to storm hardening of critical facilities, reducing the number of critical CIP-014 facilities through transmission upgrades, coordination of infrastructure development with natural gas pipelines serving generation in the region and ensuring redundancy of facilities where appropriate, to address the threat of physical or cyberattacks.*⁷⁰

Third, PJM proposes to amend the text of the benefits table in Attachment K of the *pro forma* OATT in the following manner⁷¹:

The Transmission Providers in each transmission planning region must identify the benefits they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The following set of Long-Term Regional Transmission Benefits may be useful for Transmission Providers in each transmission planning region in evaluating transmission facilities for selection in

⁶⁹ See Appendix A at 5-6.

⁷⁰ PJM proposes a ninth Factor in Section III.A.2.b, below. See also Appendix A at 5-6.

⁷¹ Note, for the reasons described in its comments, PJM proposes to consolidate the 13 benefits detailed above into five (5) benefits for the PJM Region and a core subset of benefits to apply nationwide. See Comments at III.B.2.

the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective solutions to meet transmission needs driven by changes in the resource mix and demand: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; ~~and~~ (12) increased market liquidity; and (13) enhanced reliability.⁷²

Table 1. Long-Term Regional Transmission Benefits

<i>Benefit</i>	<i>Description</i>
<i>Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement</i>	<i>Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities</i>
<i>Reduced loss of load probability [OR next benefit]</i>	<i>Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load</i>
<i>Reduced planning reserve margin [OR prior benefit]</i>	<i>While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements</i>
<i>Production cost savings</i>	<i>Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account</i>

⁷² See Appendix A at 7.

	<i>for purchases and sales outside the region, called adjusted production cost savings</i>
<i>Reduced transmission energy losses</i>	<i>Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand</i>
<i>Reduced congestion due to transmission outages</i>	<i>Reduced production costs during transmission outages that significantly increase transmission congestion</i>
<i>Mitigation of extreme events and system contingencies</i>	<i>Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system</i>
<i>Mitigation of weather and load uncertainty</i>	<i>Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns</i>
<i>Capacity cost benefits from reduced peak energy losses</i>	<i>Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses</i>
<i>Deferred generation capacity investments</i>	<i>Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas</i>
<i>Access to lower-cost generation</i>	<i>Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources)</i>
<i>Increased competition</i>	<i>Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power</i>
<i>Increased market liquidity</i>	<i>Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for long-term</i>

transmission planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion

Enhanced reliability

Ability of the grid to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event⁷³

Fourth, to address consideration of Enhanced Reliability planning for the intermediate-term (more than five years but less than the planning horizon associated with the Long-Term Regional Transmission Planning process), and to avoid the “piecemealing” of Enhanced Reliability planning across the various Transmission Planning NOPRs, PJM proposes the following addition to Attachment K of the *pro forma* OATT:

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. For planning based on a time horizon greater than five years, the regional transmission planning process shall include a transmission planning driver that ensures that the transmission system is able to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event. Criteria to be considered in the development and application of the aforementioned transmission planning driver include, but are not limited to, consideration of storm hardening of facilities and responsiveness plans, restoration planning for loss of critical infrastructure, planning to proactively prevent introduction of new CIP-014 facilities, and to “de-list” already identified CIP-014 facilities as well as gas/electric planning coordination to reduce vulnerabilities shared by both sectors. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order

⁷³ See Appendix A at 7.

No. 1000 and Order No. [final rule]. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.⁷⁴

7. The Commission Has Ample Legal Authority to Address Enhanced Reliability Planning and to Incorporate Such Matters into the Intermediate- and Long-Term Regional Transmission Planning Process

The Commission has ample authority to address Enhanced Reliability and to incorporate such matters into intermediate- and long-term transmission planning processes. Congress gave the Commission a variety of directives and tools to do so, and the Commission should not feel constrained to have to *only* address this issue through the NERC standard setting process.

For one, through FPA section 217(b)(4),⁷⁵ Congress has given authority to the Commission over long-term planning to meet the needs of load serving entities and to ensure just and reasonable rates. That section provides:

The Commission shall exercise the authority of the Commission 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***, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs (emphasis added).

In addition, issues such as ensuring that the grid is planned and operated to meet those customer needs is inherent in the determination of just and reasonable rates, terms, and conditions. In return for being obligated to pay for transmission service, the Commission clearly has the authority to ensure that the service provided meets customer needs. These requirements are part of the “terms and conditions of service” which accompany any specific rate to be approved pursuant to FPA sections 205 and 206.

⁷⁴ See Appendix A at 3.

⁷⁵ 16 U.S.C. § 824q.

Moreover, FPA section 215(i) makes clear that the Commission’s authority over service under market rules take precedence over NERC standards.⁷⁶ To the extent a transmission planning authority is operating in a market-based environment, Congress made clear through this section that the NERC standard-setting process is *not* the exclusive means to address the reliability needs of customers. Rather, Congress clearly recognized that such reliability enhancements can also be accomplished by rules developed by those entities that have linked planning and operations to the operation of markets and filed pursuant to FPA section 205.

In short, Congress clearly provided the Commission with a number of tools beyond the blunt tool of a single NERC standard to address the Enhanced Reliability focus that PJM herein urges the Commission to adopt.

B. The Final Rule Should be Crafted to Avoid a Litigious, Elongated and Disparate Compliance Process

The Commission has proposed sizable tasks to be undertaken by transmission providers, states and stakeholders. Moreover, as the Commission observes, the fleet is changing rapidly and the number of extreme weather events is increasing.⁷⁷ In addition, long-term planning analyses will, by definition, modify and evolve over time as there is no singular “right” way to undertake long-term planning analyses, especially if the Commission is to insist on a 20-year forward planning horizon.⁷⁸ Finally, because each region operates within the context of a larger Interconnection where the actions of one region can affect other regions within the

⁷⁶ 16 U.S.C. § 824o(i).

⁷⁷ NOPR at P 45.

⁷⁸ For the reasons set forth in Section III.A.2.a, below, PJM recommends that the Commission consider a 15-year planning horizon to avoid the greater level of uncertainty associated with a mandatory 20-year time horizon for Long-Term Scenario development.

Interconnection, it is critical that the transmission planning requirements and levels of compliance not differ between RTO and non-RTO regions.

The Commission needs to ensure that the compliance process be informed by the lessons learned from the Order No. 1000 compliance process inspire the compliance process. The Order No. 1000 compliance process was extremely resource-intensive and contentious, with the Commission requiring multiple tariff filings containing in great detail the minutiae of the proposed competitive process.⁷⁹ That process delayed the implementation of the Order No. 1000 reforms across the country. In addition, there remain marked differences in the level of compliance across the nation, with PJM opening 28 competitive windows,⁸⁰ while other regions, and particularly, non-RTO regions, have yet to hold a single competitive window.

1. PJM's Proposed Solution

Long-term transmission planning is an art, not a science. The specifics of how Long-Term Scenarios are developed, how many Long-Term Scenarios to run and the specifics of the processes for consultation with states and stakeholders will need to adjust and evolve over time based on state and stakeholder desires, changes in generation resources, load availability, technology and

⁷⁹ By way of example PJM was required to submit five compliance filings which then generated 43 responsive filings and five Commission orders. Disputes concerning the compliance language remain today some 11 years after its acceptance by the Commission. *See, e.g., PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,083 (2022) (rejecting, on procedural grounds only, PJM's updated compliance filing proposing to update the language in certain provisions of Schedule 6, section 1.5.8 to correct the imprecise usage of the term "Designated Entity" to align with PJM's original intent and Order No. 1000 compliance requirements); *American Municipal Power Inc., et al. v. PJM Interconnection, L.L.C.*, Docket No. EL22-80-000, Complaint Requesting Fast Track Processing, Docket No. ER22-80-000 (July 26, 2022) (challenging PJM's interpretation of the Operating Agreement provisions regarding the issuance of Designated Entity Agreements and alleging PJM's non-compliance with certain provisions of Schedule 6 of the Operating Agreement related to the Designated Entity Agreement).

⁸⁰ Since commencement of the Order No. 1000 competitive proposal windows, PJM convened a total of 28 Order No. 1000 competitive proposal windows consisting of 22 windows to address reliability and operational performance needs, and 6 long-term market efficiency windows. *See* Section III.C, *infra*. As discussed further below, PJM also held one competitive window as part of the state of New Jersey's implementation of the State Agreement Approach process under Schedule 6, section 1.5.9 of the PJM Operating Agreement. PJM is currently completing its analysis relative to New Jersey's State Agreement Approach request. *See* Section III.C, *infra*.

siting rules, and lessons learned from the extensive modeling effort to be undertaken. For these reasons, PJM urges the Commission to avoid the pitfalls of the Order No. 1000 compliance process by:

- Providing clear uniform language to be tariffed by each transmission provider that sets forth the specific goals and deliverables from the proposed Long-Term Regional Transmission Planning process. This would be standardized language that would then set the tariffed standard that each region's action would be measured against;
- Allowing the specifics of the modeling and consultation process to be developed with stakeholders and states, but addressed in each transmission provider's Manuals. This would avoid the Commission becoming embroiled, at this early stage, in litigation concerning the details of a process which, by definition, needs to evolve. Moreover, by leaving the process to the Manuals, each transmission provider would be able to design a process incorporating continued stakeholder discussions and remain nimble and adjust its processes based on the need for evolution of the process without each such change having to be litigated before the Commission;
- To the extent the Commission allows the specifics of the modeling and consultation process to be addressed in each transmission provider's Manuals rather than addressed in their tariffs, ensuring accountability by requiring periodic informational reporting on how each transmission provider's processes are meeting the Commission's overall goals as set forth in the tariffed language; and
- Ensuring consistent roll-out of the Final Rule's obligations so that non-RTO regions have the same level of accountability as would apply to RTO regions.

2. Proposed Final Rule Language to Implement PJM's Proposed Solution

Consistent with PJM's proposal outlined above, and with the Commission's finding that reforms to existing regional transmission planning and cost allocation requirements to incorporate Long-Term Regional Transmission Planning processes are needed to ensure just and reasonable rates,⁸¹ PJM recommends that Attachment K of the *pro forma* OATT be modified as follows:⁸²

⁸¹ See NOPR at P 35.

⁸² See Appendix A at 10-11.

Transmission Providers in each transmission planning region shall include in their respective Tariffs the following statement: The regional planning process set forth in this Tariff shall include a transparent long term scenario-driven process which shall, at a minimum, include long-term 15-year forward assessments of transmission needs that (a) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the forecasted resource mix and demand; (b) consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs. Development of long term planning scenarios and their application to existing planning processes shall be developed after extensive consultation with stakeholders and states in the transmission planning region. The details of the long-term scenario development process shall be developed by the transmission provider in consultation with stakeholders and states and included in the Manuals. In addition, for a period of five years after adoption of (the Final Rule), the Transmission Provider shall provide the Commission with progress reports through informational filings detailing its work on developing a long term transmission planning process consistent with Order No.xxx (Final Rule Order) and its adoption of manual provisions detailing such long term planning process.

3. PJM’s Proposal that the Commission Direct Transmission Planners to Meet Tariff Goals, Rather than Specify the Details of the Long-Term Regional Transmission Planning Process, is Consistent with Legal Precedent

PJM’s proposal described above fully complies with the “rule of reason” requirement set forth in *City of Cleveland v. FERC*.⁸³ In that case, then-Judge Scalia drew the distinction as to the level of detail needed in a tariff by stating:

As we observed earlier, there is an infinitude of practices affecting rates and service. The statutory directive must reasonably be read to require the recitation of only those practices that affect rates and service significantly, that are realistically susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous.⁸⁴

The Commission makes clear in the NOPR that it was not intending to require changes to the existing short-term reliability and market efficiency planning processes.⁸⁵ Rather, the proposed

⁸³ *City of Cleveland v. F.E.R.C.*, 773 F.2d 1368 (D.C. Cir. 1985) (“*Cleveland v. FERC*”).

⁸⁴ 773 F.2d at 1376.

⁸⁵ See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change

Long-Term Regional Transmission Planning process is designed to inform the short-term existing planning processes. It is a review of the long-term studies in relation to those short-term processes where new transmission will be ordered, an action that directly affects rates, terms and conditions. For this reason, given: (i) the nature of the new Long-Term Regional Transmission Planning process and (ii) the fact that the new Long-Term Regional Transmission Planning process does not, in and of itself, direct new transmission to be built, the “rule of reason” standard set forth in *Cleveland v. FERC* is more than met with the tariffing, through standardized language, of the goals to be met by the Commission’s new proposed long term planning process.⁸⁶

C. PJM Provides Data to Aid the Commission’s Decision Regarding the Federal Right of First Refusal. PJM Further Urges a Definitive Ruling from the Commission on the Right of First Refusal, Rather than Creating a Patchwork on this National Policy Issue

1. Any Decision About the Federal Right of First Refusal Should Apply on a Nationwide Basis

Reinstatement of any federal right of first refusal is a national policy issue that should be decided by the Commission for all jurisdictional utilities.⁸⁷ As the Commission acknowledges, the federal right of first refusal is, by definition, a federal right. The federal right of first refusal either should exist or not exist. There are no “regional differences” around this policy issue that could justify different treatments in different regions.

Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

⁸⁶ PJM’s comments on the level of tariffing apply only to the incorporation of the new proposed Long-Term Regional Transmission Planning process into existing tariffs. Obviously, more specific issues such as any changes to the federal right of first refusal or other more specific directives with an immediate impact on rates should still be included with specificity in any tariff revisions being undertaken through a compliance process.

⁸⁷ See Order No. 1000 at P 284 (finding the Commission had the authority under FPA 206 to implement the reforms adopted to eliminate provisions in Commission-jurisdictional tariffs and agreements that granted federal rights of first refusal to incumbent transmission providers with respect to the construction of transmission facilities selected in a regional plan for purposes of cost allocation).

As PJM details below, if anything, leaving this issue to each region invites discriminatory results and erosion of RTO membership stability. Therefore, as a threshold matter, PJM strongly believes that if the Commission reinstates the federal rights of first refusal, the Commission needs to do so on a nationwide basis as a compliance directive to any Final Rule issued in this proceeding. The Commission should not avoid making a concrete policy determination on the very issue it first created through its Order No. 1000 nationwide ruling. PJM urges the Commission to not simply turn this issue over to individual regions to present through FPA section 205 filings, as that approach invites the very discrimination and patchwork of negative consequences outlined herein.

More specifically, not all planning regions' voting structures and assignment of FPA section 205 rights are created equally. Nor are they the same under PJM's governing documents. For example, while PJM maintains FPA section 205 filing rights over changes to the terms and conditions of the PJM Tariff (with the exception of certain Tariff provisions that are under the exclusive control of the PJM Transmission Owners), PJM's regional planning process is set forth in Schedule 6 of its Operating Agreement. Given that FPA section 205 filing rights may differ among planning regions, it creates the potential for a piecemeal solution on what is more appropriately a nationwide issue.

By the same token, a patchwork of different rulings by planning regions on the federal right of first refusal will simply invite "RTO shopping" as transmission owners join or leave RTOs based on the Commission's reluctance to rule on this national issue that the Commission itself created. RTO membership stability in the East and RTO growth in the West will be critical to effectuating the proposals set forth in the Long-Term Regional Transmission Planning process. The Commission should be reluctant to erode RTO membership stability and growth at the very time it leans on these institutions to successfully carry out a host of new functions under the Long-

Term Regional Transmission Planning process. Transmission owners similarly situated in different regions relative to their federal right of first refusal should not receive different treatment solely on the basis of the voting and governance nuances in one region versus another, or the fact that they may have been “out-voted” on this issue of national scope. Such a result would be arbitrary, capricious and discriminatory and lead to the negative policy consequences detailed below.

Just as the Commission determined in Order No. 1000 that reforms related to removal of federal rights of first refusal must apply equally to public utility transmission providers in *all* regions,⁸⁸ the Commission should find in any Final Rule that reinstate federal rights of first refusal with or without conditions must be made applicable equally to transmission owners on a national level to avoid skewing transmission owners decisions (and their rights) among various planning regions.

2. Facts Specific to PJM’s Experience in Developing RTEP Projects Through PJM’s Order No. 1000 Competitive Process Commencing 2013 Through Fourth Quarter 2021

PJM presents the following factual information as to its experience with the competitive solicitation process. This information should provide the Commission with a complete record upon which to make its policy decision with regard to whether or not to reinstate the federal right of first refusal. The historical data presented spans the development of RTEP projects through Order No. 1000 competitive proposal windows during the period from 2013 through 2021.⁸⁹

⁸⁸ Order No. 1000 at P 265.

⁸⁹ Although Order No. 1000 was accepted as effective January 1, 2014, PJM began to use its proposal windows in 2013 for Artificial Island.

a. Order No. 1000 Competitive Proposal Window Data

Since commencement of the Order No. 1000 competitive proposal windows, PJM convened a total of 28 competitive proposal windows consisting of 22 windows to address reliability and operational performance needs, and six (6) long-term market efficiency windows.⁹⁰ During that timeframe, PJM received **a total of 1,097 project proposals**, consisting of **774 project proposals to address reliability and operational needs** and **323 project proposals to address market efficiency needs**.⁹¹ The PJM Board approved 163 reliability projects. Only **two (2)** of the **163** reliability projects were designated to a nonincumbent developer. Additionally, the Board approved **22** market efficiency projects, and only **one (1)** of the 22 market efficiency projects was designated to a nonincumbent developer. PJM’s analysis of the data is summarized in **Table 2** below:

Table 2. Order No. 1000 Competitive Window Data

Competitive Window Proposals (2013 – 2021)	Reliability	Market Efficiency	Total	
Total Project Proposals	774	323	1097	
Total Proposals: Incumbents	461	173	634	58%
Total Proposals: Nonincumbent	314	150	464	42%
Total Projects Approved	163	22	185	
Total Projects Designated to Incumbent	161	21	182	98%
Total Projects Designated to Nonincumbent	2	1	3	2%

⁹⁰ In addition, PJM opened one proposal window at the request of the New Jersey Board of Public Utilities to assist New Jersey in the selection of a State Agreement Approach project. PJM is currently completing its analysis relative to New Jersey’s State Agreement Approach request. *See* Section II.C.2.c, *infra*.

⁹¹ The data does not include the PJM-MISO Interregional Market Efficiency Project selected through the 2018/2019 RTEP Long-Term Window to rebuild the Michigan City – Trail Creek – Bosserman 138 kV transmission line located in Northern Indiana Public Service Company (“NIPSCO”) in the Midcontinent Independent System Operator (“MISO”) footprint. PJM worked with MISO under the MISO-PJM Joint Operating Agreement (“MISO-PJM JOA”). The project was assigned to NIPSCO. The estimated cost of the project was \$24.69 million (89.1 percent of the cost of the project was allocated to PJM).

This data illustrates that even when nonincumbent developers have had the opportunity to submit project proposals (a total of 464 proposals overall for consideration at the regional level), in almost all instances, the nonincumbents' proposals were not found to be the more efficient or cost effective solution. This data is further highlighted by the fact that even though the number of proposals submitted by incumbent transmission owners and nonincumbent transmission developers is not markedly different, 98 percent of the projects selected as the more efficient or cost effective solution are designated to the incumbent transmission owner and the nonincumbent transmission developers are designated two (2) percent of the projects selected.⁹²

In an effort to assist the Commission in trying to understand why nonincumbent developers were so infrequently designated projects as part of the competitive solicitation process, PJM has analyzed the data and observes that incumbent transmission owners, as opposed to nonincumbent transmission developers, generally were designated projects through the competitive window process for the following reasons:

- (i) most of the short-term reliability needs were often solved with basic incremental upgrades to existing transmission facilities, thereby rendering the nonincumbents' greenfield proposals more expansive and costly than necessary to resolve the identified need;
- (ii) because nonincumbent developers do not have unique knowledge of the transmission owners' systems, or extensive experience in building and maintaining transmission facilities,⁹³ their proposed solutions are either an overly expansive

⁹² PJM notes that the above statistics relate to onshore projects addressing reliability and economic needs. PJM recently received 80 proposals as part of its competitive solicitation for offshore wind projects to meet the state of New Jersey's public policy goals. *See* Section II.C.2.c, *infra*. The robust participation and the uniqueness of offshore wind projects that PJM has experienced provide support for PJM's suggestion that competitive solicitations remain for certain specialized projects such as Public Policy offshore wind projects. *See id.*

⁹³ *See* Order No. 1000 at P 260 (reasoning that it was not persuaded to abandon its proposed reforms to federal rights of first refusal based on arguments that incumbent transmission owners are better situated to build and operate transmission facilities because they "may have unique knowledge of their own transmission systems, familiarity with the communities they serve, economies of scale, experience in building and maintaining transmission facilities, and access to funds needed to maintain reliability . . .").

overbuild to address the identified need or do not solve the problem;⁹⁴

- (iii) proposed greenfield solutions were more risky in terms of delays due to siting and regulatory approvals; or
- (iv) transmission expansion via the use of existing easements and rights-of-way has less environmental impact and is typically far less expensive.

For these reasons, PJM has generally found that nonincumbent transmission developers generally have been unable to propose a more efficient or cost-effective solution to address an identified transmission need, as compared to proposals submitted by incumbent transmission owners. PJM provides below specific examples of actual proposals submitted through competitive windows that demonstrate why incumbent transmission owners' proposals were nearly always found to be the more efficient or cost-effective solution.

b. Specific Examples Demonstrating Why, Historically, Transmission Projects Have Been Awarded to Incumbent Transmission Owners

PJM provides the following specific examples demonstrating why, historically, transmission projects have been awarded to incumbent transmission owners.

- *Upgrades to existing transmission facilities are not available to a nonincumbent developer⁹⁵ and are almost always the more efficient or cost effective solution for short-term reliability needs.*

Many of the violations or constraints for short-term projects are resolved with upgrades to existing transmission facilities. Because upgrades to existing transmission facilities must be designated to the incumbent transmission owner who owns the transmission facilities, they are not

⁹⁴ Of the 185 RTEP projects selected through competitive proposal windows, two reliability projects and one market efficiency project were designated to nonincumbent transmission developers. See Table 2, above.

⁹⁵ Operating Agreement, Schedule 6, section 1.5.8(l).

available to be designated to a nonincumbent developer.⁹⁶ Thus, if the nonincumbent developer wishes to be designated to construct a project to address short-term reliability needs, it must submit a proposal for a greenfield solution to solve a posted system need. In most instances, an upgrade is the more efficient, cost-effective solution because it will generally be less costly or less likely to be subject to delay as compared to building a new greenfield project, which requires, among other things, land acquisition and regulatory approvals. Although one can argue for a more robust solution, the costs of such a solution substantially outweigh its benefits, especially when addressing the type of needs that drove the competitive solicitation in the first place.

By way of example, as demonstrated in **Table 3** below, PJM received four project proposals related to the 2021 RTEP Proposal Window 1 – Cluster No. 1,⁹⁷ which was opened on July 2, 2021, to address multiple voltage drop violations identified in the Allegheny Power System (“APS”) region.⁹⁸

- Proposal Nos. 779⁹⁹ and 919¹⁰⁰ were submitted by an incumbent transmission owner and were upgrades to its existing transmission facilities.
- Proposal Nos. 560¹⁰¹ and 608¹⁰² were submitted by a nonincumbent transmission developer and were greenfield projects.

⁹⁶ *Id.*

⁹⁷ PJM conducted Proposal Window 1 for 60 days beginning July 2, 2021 and closing August 31, 2021. Two entities submitted four proposals for Cluster No. 1 of Proposal Window 1.

⁹⁸ See Initial Review and Screening 2021 RTEP Proposal Window 1 – Cluster No. 1 at 2 - 4 (Dec. 14, 2021) at <https://www.pjm.com/-/media/committees-groups/committees/teac/20>.

⁹⁹ Cost estimate was \$11,926,786.

¹⁰⁰ Cost estimate was \$1,668,215.

¹⁰¹ Cost estimate was \$135,548,201.

¹⁰² Cost estimate was \$77,592,915.

After considering all proposals, PJM selected Proposal No. 919. Based on PJM’s evaluation, Proposal No. 919: (i) solved the voltage drop reliability criteria violation, (ii) did not create any additional reliability criteria violations, and (iii) was the more cost-effective solution.¹⁰³ Despite the fact that the nonincumbent transmission developer submitted cost commitments with its Proposal Nos. 560 and 608 (and the incumbent transmission owner’s proposals did not), PJM found that the nonincumbent transmission developer’ project cost estimates were considerably higher than Proposal No. 919 with no additional benefits identified to justify the cost differential. PJM received no stakeholder comments in opposition to the selected solution at the relevant Transmission Owners Advisory Committee (“TEAC”) meeting,¹⁰⁴ nor afterward via the Planning Community portal on the PJM Website.

Table 3. 2021 RTEP Proposal Window 1 – Cluster No. 1 (Reliability)

Proposal ID	779	919	560	608
Proposal Description	Convert Shingletown 230 kV Substation into a six-breaker ring bus.	Upgrade the Shingletown #82 230-46 kV Transformer Circuit	The Persia - Elimsport 230 kV Transmission Project	The Persia - Yeagertown 230 kV Transmission Project
Incumbent (Y/N)	Y	Y	N	N
Project Type	Upgrade	Upgrade	Greenfield	Greenfield
Cost (\$M)	11.93	1.67	135.55	77.59
Cost Capping (Y/N)	N	N	Y	Y

¹⁰³ See Initial Review and Screening 2021 RTEP Proposal Window 1 – Cluster No. 1 at 2 - 4 (Dec. 14, 2021) at <https://www.pjm.com/-/media/committees-groups/committees/teac/20>.

¹⁰⁴ As discussed below, the TEAC is a stakeholder process pursuant to which PJM and stakeholders provide advice and recommendations to aid in the development of the RTEP.

- ***Because nonincumbent transmission developers either generally do not have a detailed working knowledge of the transmission owner’s system or can only be designated a greenfield solution, their proposals tend to be an overbuild of what is needed or justified to address the identified problem.***

An example of this scenario can be found in the proposals submitted for the 2020/2021 Long-term Window 1, Cluster No. 1,¹⁰⁵ which is illustrated in **Table 4**, below. This proposal window was open for 120 days beginning January 11, 2021, to address clustered groups of congestion drivers. Cluster No. 1 specifically sought congestion relief along the French’s Mill to Junction 138 kV line in the APS zone. The Cluster No. 1 constraint was due to a limitation on terminal equipment. As such, the more efficient or cost-effective solution to address the need was likely to be an upgrade to the limiting equipment. PJM evaluated five (5) project proposals submitted for Cluster No. 1. The following three proposals are relevant for this discussion:¹⁰⁶

- Proposal No. 547, submitted by a nonincumbent transmission developer, proposed to build a new 500 kV transmission line connecting two existing substations with a cost estimate of \$128,751,561. The project proposal was found to be 99.97 percent effective in mitigating the congestion.
- The remaining two project proposals (Proposal Nos. 425 and 756) were submitted by an incumbent transmission owner and found to be 100 percent effective in mitigating the identified congestion.
 - Proposal No. 425 proposed to replace terminal equipment at the transmission owner’s existing facility and reconductor an existing transmission line with cost estimate of \$11,985,300.
 - Proposal No. 756 proposed to replace terminal equipment at the transmission owner’s existing facility with a cost estimate of \$773,700.

¹⁰⁵ See <https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220111/20220111-informational-only-2022-2021-long-term-window-1-carbon-impact-of-selected-market-efficiency-projects.ashx>.

¹⁰⁶ Proposal Nos. 102 and 540 are not relevant to this discussion because they proposed to install capacitor banks at the Reston and Bull Run 230 kV substations. The proposals were submitted by an incumbent transmission owner and did not alleviate the congestion driver.

After considering all proposals, PJM selected Proposal No. 756. Although the nonincumbent developer's proposal was 99.97 percent effective in mitigating the congestion, PJM found that the nonincumbent developer's proposal was an expansive overbuild of what was required to address the need. Additionally, PJM found that the proposal's additional benefits are too small to justify the cost estimate that was more than 166 times greater than the more cost efficient of the two proposals submitted by the incumbent transmission owner that resolved the congestion driver.

PJM received no stakeholder comments in opposition to the selected solution at the relevant TEAC meetings during which PJM's evaluation and selection of the project were vetted, nor afterwards via the Planning Community portal on the PJM Website.¹⁰⁷

¹⁰⁷ It is important to note that arguments that "absent a transparent, competitive process there is nothing to stop a transmission owner from submitting a more costly solution than is necessary to resolve the problem" ignores the safeguards put into place by Order Nos. 890 and 1000 whereby (i) PJM, as the independent regional planner, is responsible to perform the analysis and select the more efficient or cost effective solution for inclusion in the RTEP regardless whether the project is selected through a competitive proposal window or selected outside the window process; and (ii) any project selected by PJM for inclusion in the RTEP must be vetted through PJM's open, transparent stakeholder process that affords stakeholders timely and meaningful opportunity to review and provide comments regarding PJM's evaluation and selection of all projects recommended to the PJM Board for review and approval. *See, e.g.*, Operating Agreement, Schedule 6, section 1.5.6(a) (providing that RTEP Projects shall be developed through an open and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committees).

Table 4. 2020/2021 Long-term Window 1, Cluster No. 1 (Market Efficiency)¹⁰⁸

Proposal ID	547	425	756
Proposal Description	Black Oak-Bismark 500 kV Line	French’s Mill-Junction 138 kV Terminal Upgrades and Messick Rd-Ridgeley 138 kV Line Reconductor	French’s Mill-Junction 138 kV Terminal Upgrades
Incumbent (Y/N)	N	Y	Y
Project Type	Greenfield	Upgrade	Upgrade
In-Service Cost (\$M)	128.75	11.99	0.77
Cost Capping (Y/N)	Y	N	N

- *Because the nonincumbent developers do not have working knowledge of the transmission owners’ systems or experience in building and maintaining transmission facilities, their proposed solutions cannot be selected because they do not solve the problem.*
 - *Example of proposals submitted to address economic constraints where even though the nonincumbent developer’s proposal addressed constraints in both Cluster Nos. 1 and 2 and the upgrade proposals did not, it did not satisfy the Operating Agreement’s benefit-to-cost ratio requirement, significantly exceeded the cost estimates of the three projects selected and presented greater risk than the projects selected due to constructing and siting challenges.*

One example of this scenario can be found in the proposals submitted for the 2020/2021 Long-term Window 1, Cluster No. 2,¹⁰⁹ which is illustrated in **Table 5**, below. This proposal window was opened for 120 days beginning January 11, 2021, to address clustered groups of congestion drivers. Cluster No. 2 specifically sought congestion relief along the Plymouth Meeting to Whitpain 230 kV line in the PECO Energy Company (“PECO”) zone. The Cluster

¹⁰⁸ For market efficiency projects the project cost is shown as in-service year dollars for the purpose of calculating the benefit-to-cost ratio over a period of 15 years.

¹⁰⁹ See <https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220111/20220111-informational-only-2022-2021-long-term-window-1-carbon-impact-of-selected-market-efficiency-projects.ashx>.

No. 2 constraint was due to a limitation on terminal equipment. PJM evaluated four (4) project proposals. Three (3) project proposals (Proposal Nos. 399,¹¹⁰ 704¹¹¹ and 735¹¹²) were submitted by the incumbent transmission owner. All three project proposals were upgrades to the incumbent transmission owner's existing transmission facilities. Project cost estimates totaled less than \$15 million for each of the individual proposals. Each proposal individually solved the congestion driver and met the benefit/cost ratio requirements. However, Proposal No. 704 yielded a benefit to cost ratio that far exceeded all of the other proposals.

The fourth project proposal, Proposal No. 227, was a greenfield project submitted by a nonincumbent transmission developer with estimated costs of \$73.51 million and presented a number of issues that prevented it from being the more efficient or cost effective solution. For starters, this proposal mitigated the congestion but demonstrated only a 1.09 benefit-to-cost ratio; and thus did not satisfy the Operating Agreement benefit-to-cost ratio requirement of 1.25.¹¹³ Even though this proposal included cost commitment provisions (and the other proposals did not), the estimated cost of the project far exceeded the estimated costs for Proposal Nos. 399, 704 and 735. Additionally, this greenfield proposal was more risky than the other three transmission owner upgrade proposals because it presented challenges related to siting and construction through wetlands, as well as other potential environment concerns, identified by the project proposer.

After considering all four proposals, PJM selected Proposal No. 704 at the November 2, 2021 TEAC meeting. Based on PJM's evaluation, Proposal No. 704 solved the congestion driver,

¹¹⁰ Cost estimate was \$8,415,426

¹¹¹ Cost estimate was \$618,062.

¹¹² Cost estimate was \$14,975,929.

¹¹³ Operating Agreement, Schedule 6, section 1.5.7(d).

did not create any additional reliability violations, was the more cost effective solution and had a benefit to cost ratio of 75.31 that far exceeded all other proposals.

PJM received no stakeholder comments in opposition to the selected solution at the relevant TEAC meeting, or afterward via the Planning Community portal on the PJM Website.

Table 5. 2020/2021 Long-term Window 1, Cluster No. 2 (Market Efficiency)

Proposal ID	399	704	735	227
Proposal Description	Plymouth Meeting-Whitpain 230 kV Terminal Upgrades	Plymouth Meeting-Whitpain 230 kV Terminal Upgrades	Plymouth Meeting-Whitpain 230 kV Line Reconductor	Old Limestone-Doe Run 500/230 kV Project
Incumbent (Y/N)	Y	Y	Y	N
Project Type	Upgrade	Upgrade	Upgrade	Greenfield
In-Service Cost (\$M)	8.42	0.62	14.98	73.51
Cost Capping (Y/N)	N	N	N	Y

- *Example of Proposals submitted to address reliability violations where the nonincumbent transmission developer’s proposal did not resolve all the violations posted and the incumbent transmission owner’s upgrade resolved additional benefits beyond the needs posted in the proposal window*

Another example under this category can be found in the 2021 RTEP Proposal Window No. 1, Cluster No. 9,¹¹⁴ which is illustrated in **Table 6**, below. This proposal window was opened for 60 days beginning July 2, 2021 to address reliability violations identified on a clustered group of flowgates. PJM received three (3) project proposals to address the reliability violations. Two

¹¹⁴ See Final Review and Recommendation at <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-final-review-and-recommendation-2021-rtep-window-1-cluster-9.ashx>.

project proposals (Proposal Nos. 202¹¹⁵ and 786¹¹⁶) were submitted by the incumbent transmission owner and were upgrades to the incumbent transmission owner's existing transmission facilities. The third project proposal (Proposal No. 503¹¹⁷) was a greenfield project submitted by a nonincumbent transmission developer.

Based on PJM's evaluation of the proposals submitted, PJM found that Proposal Nos. 202 and 786 solved all 30 flowgates listed in the Problem Statement posted for the window. PJM also found that, in pursuing a more efficient or cost-effective transmission solution to identified regional needs: (i) Proposal No. 202 would also address identified aging infrastructure needs not included in the violations posted; and (ii) Proposal No. 786 would require PJM to convert a Supplemental Project to a baseline project.

On the other hand, while Proposal No. 503 was only \$5.5 million more than Proposal No. 202 and included cost commitment provisions (and the other proposals did not), Proposal No. 503 did not resolve five (5) of the 30 flowgates; and, while not evident based on a summary review of the proposal, Proposal No. 503 required greenfield construction that "may" delay timely completion of the reliability project. Given those factors, PJM selected Proposal No. 202 as the more efficient or cost effective solution.

PJM received no stakeholder comments in opposition to the selected solution at the relevant TEAC meetings, or afterward via the Planning Community portal on the PJM Website.

¹¹⁵ Cost estimate was \$8.87 million.

¹¹⁶ Cost estimate was \$1.31 million.

¹¹⁷ Cost estimate was \$14.415 million.

Table 6. 2021 RTEP Proposal Window No. 1, Cluster No. 9 (Reliability)

Proposal ID	202	786	503
Proposal Description	Delphos Area Line Rebuilds	Haviland Sectionalizing Addition	Rockford - West Van Wert 69 kV Transmission Project
Incumbent (Y/N)	Y	Y	N
Cost Commitment (Y/N)	N	N	Y
Project Type	Upgrade	Upgrade	Greenfield
Cost (\$M)	8.87	1.31*	14.42
Cost Capping (Y/N)	N	N	Y

* Plus \$65.36M for S2389

- *Because nonincumbent developer proposals require greenfield construction, they pose greater concerns, particularly “unknown” risks, regarding siting delays and additional costs.*

An example of this category can be found in the proposals submitted through the 2020 RTEP Proposal Window No. 1, Cluster Nos. 1 and 2,¹¹⁸ which is illustrated in **Tables 7 and 8**, below. This proposal window was opened for 60 days beginning July 1, 2020 to address reliability criteria violations identified on a clustered group of flowgates located near Dulles Airport in the Dominion zone. Both Clusters are relevant for this discussion.

For Cluster No. 1, PJM evaluated five (5) project proposals. Four (4) project proposals (Proposal Nos. 26, 479, 735 and 740) submitted by the incumbent transmission owner were upgrades to the incumbent transmission owner’s existing transmission facilities. The cost estimates for the four project proposals were less than \$2.5 million each. Cluster No. 1 included violations for both lines 2210 and 2174 from Brambleton to Evergreen Mills.

¹¹⁸ See Final Review and Recommendation at <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20210106/20210106-cluster-no-1-2-final-review-and-recommendation.ashx>.

Project proposals Nos. 26 (full reconductoring, costing \$2.32 million) and 479 (partial reconducting, costing \$1.85 million) proposed to solve violations for line 2172. Project proposals Nos. 735 (full reconductoring, costing \$2.26 million) and 740 (partial reconductoring, costing \$2.01 million) proposed to solve violations for line 2210.

The remaining Proposal No. 721 was a greenfield solution submitted by a nonincumbent transmission developer with a cost estimate of \$29.25 million. Proposal No. 721 solved the reliability criteria violations for both Cluster Nos. 1 and 2 and included cost commitment provisions (and the other three proposals did not). However, Proposal No. 721's increased costs, potential delays due to construction requirements and risks associated with siting the project through wetlands and waterways, prevented PJM from selecting Proposal No. 721.

Instead, even though a full reconductoring of lines 2210 and 2172 was not required to resolve the reliability violations, PJM found that the relatively modest increases of a full reconductoring warranted selecting Project proposals Nos. 26 (adding approximately \$0.5 million) and 735 (adding approximately \$0.24 million in costs) as the more efficient or cost effective solution.

For Cluster No. 2, in addition to Project Proposal No. 721, which was addressed in the Cluster No. 1 analysis above, PJM received three other greenfield proposals (Proposal Nos. 704,¹¹⁹ 376¹²⁰ and 883¹²¹) submitted by an incumbent transmission owner. Based on its analysis, PJM found Proposal No. 704 to be the more efficient or cost effective solution of the four proposals submitted to address Cluster No. 2.

¹¹⁹ Cost estimate was \$5.70 million.

¹²⁰ Cost estimate was \$17.70 million.

¹²¹ Cost estimate was \$41.20 million.

In sum, while PJM gave full consideration to the fact that Proposal No. 721 addressed the reliability violations included in both Cluster Nos. 1 and 2, PJM found that for Cluster No. 1, Proposal No. 721: (i) significantly exceeded the costs of Proposal Nos. 26, 735 and 704 combined, (ii) presented significant right of way and siting concerns as compared to the other projects combined; and (iii) the cost commitment provisions did not outweigh the concerns presented by Proposal No. 721.

Table 7. 2020 RTEP Proposal Window No. 1, Cluster No. 1

Proposal ID	26	479	735	740	721
Proposal Description	Brambleton to Evergreen Mills - Full Reconductor	Brambleton to Evergreen Mills - Partial Upgrade	Brambleton to Evergreen Mills - Full Reconductor	Brambleton to Evergreen Mills - Partial Reconductor	Stonewater - Waxpool 230 kV Transmission Project
Incumbent (Y/N)	Y	Y	Y	Y	N
Project Type	Upgrade	Upgrade	Upgrade	Upgrade	Greenfield
In-Service Cost (\$M)	2.32	1.85	2.26	2.01	29.25
Cost Capping(Y/N)	N	N	N	N	Y

Table 8. 2020 RTEP Proposal Window No. 1, Cluster No. 2

Proposal ID	704	376	883	721
Proposal Description	Waxpool Loop - Nimbus to Farmwell line extension	Waxpool Loop - Loop Line #2031 Option	Waxpool Loop - Shellhorn Option	Stonewater - Waxpool 230 kV Transmission Project
Incumbent (Y/N)	Y	Y	Y	N
Project Type	Greenfield	Greenfield	Greenfield	Greenfield
In-Service Cost (\$M)	5.7	17.7	41.2	29.25
Cost Capping(Y/N)	N	N	N	Y

c. Other Factors that the Commission Should Consider in Adopting Any Final Rule Addressing Competitive Solicitation Processes

Other factors, while not necessarily quantifiable here, nevertheless should be considered by the Commission in adopting any Final Rule. More specifically, the evaluation of every project proposal submitted through a proposal window to address PJM’s reliability and market efficiency needs has significantly increased PJM’s administrative and analytical workload. Examples include:

- PJM has had to perform “consultant” work for nonincumbent transmission developers who are not fully versed in certain powerflow analyses;
- Cost commitment provisions have not realized the benefits expected but, nonetheless, require extensive analysis by PJM personnel, as well as engagement of outside consultants;
- The collection of fees for project proposals has added another administrative layer to the planning process;
- PJM planning staff has expended significant amounts of time evaluating and differentiating among multiple, similar proposals through the proposal windows in order to select the more efficient, cost effective solution;¹²²
- Significant time is expended by engineers and legal staff in developing responses to questions regarding competitive proposal windows as compared to the amount of time spent performing powerflow analyses; and
- The level of transparency required under Order No. 1000 planning processes has made it more challenging to work through issues that must be maintained as confidential (*e.g.*, identification and selection of projects needed to address CIP-014 needs), resulting in additional processes to allow PJM to plan for such needs.

All of this work, and more, has placed an enormous strain on PJM resources. In addition to the competitive windows being both time- and resource-intensive, the base case for reliability

¹²² Even when incumbent transmission owners know the right solution to address the posted need, they tend to submit multiple project proposals in order to improve their chances of being designated a project. Additionally, competition has forced incumbent transmission owners to focus on smaller solutions to solve posted needs in order to submit the lower cost solution.

projects needed in five years or less must be completed within the annual RTEP cycle as it forms the baseline for determining network upgrade facilities and expansion costs for interconnection to the Transmission System that cause the need for those facilities beyond those required for system reliability.¹²³

As the above data illustrates, in the end, the extensive amount of proposals submitted by nonincumbent transmission developers for short-term reliability projects and for market efficiency needs often are not found to be the more efficient or cost-effective solution. That is not to say that competition could not provide the benefits anticipated by the Commission in Order No. 1000. Rather, the competitive process should be focused on those specific areas where proposers have an ability to provide innovative solutions that can ensure cost savings to ratepayers and enhanced reliability for the system.¹²⁴

d. If the Commission Does Not Reinstate the Federal Right of First Refusal, PJM Proposes that the Commission Consider a More Targeted Competitive Process

PJM proposes, based on its nine years of experience with its competitive process, that if the Commission decides not to reinstate the federal right of first refusal, any future competitive process should be more targeted than what exists today to address specialized circumstances, such as public policy offshore wind or specialized Long-Term Regional Transmission projects that comprise multi-zones.

For example, in order to facilitate the state of New Jersey's goal to acquire 7,500 MW of offshore wind generation by 2035, in November 2020 the New Jersey Board of Public Utilities

¹²³ See PJM, *Manual 14B: PJM Region Transmission Planning Process*, § 2.3.1 (rev. 51 Dec. 15, 2021).

¹²⁴ NOPR at P 353.

(“NJ BPU”) formally requested¹²⁵ that PJM open a competitive proposal window to solicit project proposals that improve and/or expand the PJM transmission system to provide for the deliverability of the offshore wind generation.¹²⁶ Consistent with the NJ BPU’s request, PJM used its existing competitive solicitation process¹²⁷ to convene a competitive proposal window¹²⁸ to solicit transmission solutions to interconnect and provide for the deliverability of up to 7,500 MW of offshore wind generation.

PJM received a diverse set of approximately 80 project proposals. The proposals were categorized into four options based on the function and location of the proposal.¹²⁹ This SAA Proposal Window offered proposers the opportunity to submit project proposals that are not limited to upgrades to existing transmission facilities, because New Jersey’s request under the State Agreement Approach requires expansion of the transmission system where none exists today. Therefore, the SAA Proposal Window, by its very nature, encouraged submittal of innovative greenfield solutions, allowing incumbent transmission owners and nonincumbent transmission

¹²⁵ *In the Matter of Offshore Wind Transmission*, Order, NJ BPU Docket No. QO20100630, at 7 (Nov. 18, 2020) (“NJ BPU Order”).

¹²⁶ See *PJM Interconnection, L.L.C.*, New Jersey State Agreement Approach Study Agreement, SA No. 5890, Docket No. ER21-689-000 (Dec. 18, 2020) (“December 2020 Filing”) (accepting a State Agreement Approach Study Agreement between the NJ BPU and PJM (“SAA Study Agreement”). The SAA Study Agreement was accepted by the Commission, effective November 18, 2020. *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,090 (2021). The SAA Study Agreement provides for coordination between PJM and the State of New Jersey to ensure that the PJM Transmission System can accommodate New Jersey’s public policy goal of procuring 7,500 MW of offshore wind generation by 2035.

¹²⁷ Operating Agreement, Schedule 6, section 1.5.8(c) (the State Agreement Approach process does not require convening a competitive proposal window).

¹²⁸ PJM opened the “2021 Proposal Window to Support NJ OSW” on April 15, 2021 (“SAA Proposal Window”). See <https://pjm.com/planning/competitive-planning-process.aspx>.

¹²⁹ The four options include: Option 1a – onshore transmission upgrades to resolve potential reliability criteria violations on PJM facilities based on applicable planning criteria; Option 1b – onshore new transmission connection facilities; Option 2 – offshore new transmission connection facilities; and Option 3 – offshore new transmission network facilities.

developers to compete on a more level playing field.¹³⁰ This particular competitive window provides a good example of where the competitive process could be used.

Given the above, even if the Commission does not reinstate the federal right of first refusal, the time is ripe for the Commission to consider refocusing the application of the competitive process to those limited project types for which competition could provide the benefits contemplated under Order No. 1000.

3. If the Commission Implements a Conditional Federal Right of First Refusal for Certain Jointly-Owned Transmission Facilities, the Commission, Not RTOs, Should Evaluate the Financial Structure of a Joint-Ownership Proposal

The Commission finds that there may be misaligned incentives associated with the development of transmission facilities.¹³¹ In order to address this concern, while balancing potential cost-related benefits of competitive transmission development processes, the Commission proposes to permit the exercise of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission owner with the federal right of first refusal for such transmission facilities establishing joint-ownership of the transmission facilities as proposed in the NOPR (“Joint-Ownership ROFR”).¹³² The Commission qualified its proposal to state that it did not intend to require the establishment of any particular federal rights of first refusal.¹³³ Regardless, PJM

¹³⁰ Once proposals from transmission developers have been evaluated through the PJM planning process, and following consultation with PJM, the State of New Jersey (through the NJ BPU) has the option (but is not required) to select one or more of the proposed projects that it finds the more efficient or cost effective solution to meet its public policy goals. 2021 State Agreement Approach Process Guidance Document (Sept. 24, 2021), <https://www.nj.gov/bpu/pdf/ofrp/SAA%20Process%20Overview.pdf>.

¹³¹ NOPR at P 355.

¹³² *Id.* at PP 336, 351, 365 (qualifying joint ownership structures could include unaffiliated nonincumbent transmission developers or another unaffiliated entity, including another incumbent transmission provider).

¹³³ *Id.* at P 355.

reiterates that if the Commission decides to permit the establishment any federal rights of first refusal, such a decision must be included in a Final Rule by way of a compliance directive that applies nationwide.¹³⁴

As to who should determine (i) whether or not the joint-ownership proposal offers unaffiliated entities a reasonable chance at meaningful participation and investment in the proposed regional transmission facility or (ii) what standards, such as ownership share percentages or load-ratio share offer requirements, should govern whether a particular joint-ownership structure qualifies for the presumptive Joint-Ownership ROFR, PJM urges the Commission not to place the RTO in the position of evaluating the financial structure of a joint-ownership proposal.¹³⁵

Assigning such decisions to the RTO thrusts the regional planner into a quasi-regulatory role, which it is ill-fitted to handle and which is clearly far afield from the traditional planning process that Order No. 1000 assigned to RTOs. Because the burden of proof appropriately lies with the transmission owner seeking approval of its joint-ownership proposal, PJM proposes that a more balanced approach would be for the Commission to provide a means by which an incumbent transmission owner could seek pre-determination of the joint-ownership proposal by

¹³⁴ See Section II.C.1, *supra*.

¹³⁵ By way of example, the Commission's regulations permit an owner or operator of a generating facility with a max net power production capacity of greater than 1 MW to obtain Qualifying Facility ("QF") status either by submitting a self-certification or by applying for a Commission certification of QF status. See 18 C.F.R. § 292.207. QF self-certification is effective upon filing and would remain effective if a protest is filed, until such time as the Commission rules that certification is revoked. *Id.* at §292.207(a)(3). See also, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (2020), *order on reh'g*, Order No. 872-A, 173 FERC ¶ 61,158 (2020).

the Commission through a process that will not delay the transmission planner's ability to develop its regional transmission plan.¹³⁶

Nevertheless, even this process could create further bureaucratic delays in getting needed transmission built. Although joint ownership projects have proven beneficial, the Commission has not shown why they should be made a *condition precedent* to a transmission planner making a direct assignment to an incumbent transmission owner should the Commission otherwise seek to pare back the right of first refusal as it exists today. In short, little would be served by creating a hurdle to a direct assignment to the best entity to build the project (be it an incumbent or a non-incumbent) by requiring joint ownership as a condition precedent to reinstating the federal right of first refusal. The Commission should make a definitive ruling on the federal right of first refusal issue in its entirety rather than making half a decision by erecting a new condition associated with the federal right of first refusal.

While PJM believes it could incorporate this Joint-Ownership ROFR proposal in pretty much the same way it applies its exemption processes for immediate-need reliability projects,¹³⁷ violations on transmission facilities below 200 kV or thermal reliability violations¹³⁸ on transmission substation equipment,¹³⁹ PJM is concerned that if the Commission does not provide for a fast-track process by which the Commission could find that an incumbent transmission owner's joint-ownership structure meets the requirements for the Joint-Ownership ROFR and the

¹³⁶ Having the Commission pre-determine an incumbent transmission owner's joint-ownership proposal should help avoid uncertainty and unnecessary litigation by confirming the parties' rights and responsibilities upfront relative to the jointly-owned structure and the agreement's conformance with tariff provisions implementing the option. NOPR at PP 366, 369.

¹³⁷ Operating Agreement, Schedule 6, section 1.5.8(m)(1).

¹³⁸ *Id.*, section 1.5.8(n).

¹³⁹ *Id.*, section 1.5.8(p).

Final Rule does not include detailed criteria by which a transmission provider may implement the right of first refusal, such a proposal may delay the transmission provider's ability to timely develop transmission projects. Of course, this concern is more apropos for short-term reliability projects that are selected within an eighteen-month annual planning cycle, as opposed to market efficiency needs or needs identified through the Long-Term Regional Transmission Planning process that have a longer lead time.

4. Summary of Issues PJM Urges the Commission to Consider Regarding the Federal Right of First Refusal

In sum, the Commission needs to make a substantive call on the policy issue associated with reinstating the federal right of first refusal and not evade the issue by assigning it to each region pursuant to FPA section 205 filings. The Commission eliminated the federal right of first refusal nationwide in Order No. 1000 and needs to address any changes to that policy on a nationwide basis. There simply are no "regional differences" on this issue. To leave it to each region is to invite discriminatory results and further erode RTO membership stability and RTO growth. In addition, PJM urges the Commission to reconsider whether making joint ownership arrangements a condition precedent of reinstating the federal right of first refusal does not just create a new bureaucratic hurdle that slows down development of needed new transmission and assignment to the best entity able to get that transmission built in a timely and cost effective manner.

If the Commission determines to permit the exercise of federal right of first refusal for transmission facilities selected in the regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission owner with the federal right of first refusal for such facilities establishing joint ownership of the transmission, PJM requests that the Commission does not place the regional transmission planner in the role of regulator, but instead provides some sort

of fast track process by which the Commission may pre-determine whether or not an incumbent transmission owner's joint-ownership structure qualifies for the Joint-Ownership ROFR in a way that does not delay the transmission provider's ability to timely develop its regional transmission plan.

III. COMMENTS ON SPECIFIC PROPOSALS IN THE NOPR

A. PJM Supports the Commission's Proposal to Implement Long-Term Regional Transmission Planning, Subject to the Conditions Described Below

The Commission determines, in a sweeping manner, that currently-effective regional transmission planning processes do not meaningfully perform forward assessments of transmission needs, leading to insufficient regional transmission development and a shift towards greater transmission expansion outside of the regional transmission planning process.¹⁴⁰ The Commission therefore proposes reforms aimed at requiring forward-looking, Long-Term Scenario planning to meet transmission needs driven by “changes in the resource mix and demand.”¹⁴¹

Although PJM currently prepares a 15-year forward-looking transmission planning analysis, PJM has acknowledged the need to further enhance its current analysis by more formally considering, with state and stakeholder input, future customer trends and needs, along with policy developments.¹⁴² Indeed, in May 2022, PJM released its “Enhanced 15-Year Long-Term (Master Plan) White Paper,” outlining how best to work with states and other stakeholders to identify, from among an array of future scenarios, those scenarios which transmission planners could utilize to justify moving forward with directives to build new transmission to support customer needs and

¹⁴⁰ NOPR at P 45.

¹⁴¹ *Id.*

¹⁴² *See* PJM Initial ANOPR Comments at 41-46; PJM ANOPR Reply Comments at 7-10.

policy goals.¹⁴³ PJM therefore supports the Commission’s proposal to require transmission planners to conduct Long-Term Regional Transmission Planning through the evaluation of Long-Term Scenarios incorporating changes in resource mix and demand.

While PJM is generally supportive of the Commission’s proposed Long-Term Regional Transmission Planning process, there are several elements that PJM believes are unworkable or inappropriate for the PJM Region, and therefore need modification before they are incorporated into a Final Rule. PJM provides comments below on each element of the proposed Long-Term Regional Transmission Planning process, setting forth the areas where PJM agrees with the Commission’s proposal, as well as areas where PJM recommends that the Commission make modifications. Additionally, for the reasons set forth below, PJM believes it is important that the Commission confirm in its Final Rule that the proposals contained in the NOPR are meant to apply to long-term planning processes only, and do not modify existing regional reliability and market efficiency planning processes.

1. PJM Supports the Concept of a Long-Term, Scenario-Based, Regional Transmission Planning Process as an Add-On to Existing Regional Transmission Planning Processes, and Requests that the Commission Confirm that the Final Rule Will Not Modify Existing Order No. 1000 Planning Processes for Addressing Transmission Needs Driven by Reliability or Market Efficiency Considerations

PJM appreciates the Commission’s clarification that the proposed Long-Term Regional Transmission Planning process is not intended to modify the existing short-term planning processes to address reliability and market efficiency needs.¹⁴⁴ Those short-term processes are

¹⁴³ PJM Interconnection, Enhanced 15-Year Long-Term (Master Plan) White Paper (May 10, 2022) <https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220525-long-term/enhanced-long-term-planning-discussion-document.ashx> (“Master Plan White Paper”). PJM has included the Master Plan White Paper as Appendix C to these comments.

¹⁴⁴ See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change

critical to ensuring that needed reliability and market efficiency projects, as well as state public policy projects endorsed by states through PJM’s State Agreement Approach process,¹⁴⁵ are able to proceed without those existing processes being brought into doubt or otherwise subject to collateral attack as a result of the proposed Long-Term Regional Transmission Planning process set forth in the NOPR. Clearly, the Long-Term Regional Transmission Planning process should help to inform the choice of projects considered in those short-term planning processes, and PJM is committed to such a symbiotic approach should the Long-Term Regional Transmission Planning process be embraced in a Final Rule.

Nevertheless, the Commission needs to be vigilant in its Final Rule that the NOPR proposals not be used as a litigation sword to thwart the continuation of the short-term planning processes presently underway.¹⁴⁶ New transmission is needed, both in the short- and long-term. It would be most ironic if the Commission’s goals outlined in the NOPR become a new means to further entangle what already is a contentious and litigious short-term planning process.

Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

¹⁴⁵ See Operating Agreement, Schedule 6, section 1.5.9(a). As discussed, PJM’s State Agreement Approach is a mechanism pursuant to which a state or group of states can agree to pay for their own public policy-driven transmission projects. See, e.g., *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024, at P 2 (2022). The State Agreement Approach was proposed by PJM with its Order No. 1000 compliance filing and its use was approved by the Commission in 2013. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 142-143 (2013), *order on reh’g and compliance*, 147 FERC ¶ 61,128, at P 92 (2014); *order on reh’g and compliance*, 150 FERC ¶ 61,038, *order on reh’g and compliance*, 151 FERC ¶ 61,250 (2015).

¹⁴⁶ See n.4, *supra* (explaining that for purposes of these Comments, PJM focuses on three different planning horizons within the planning process: (i) the present five-year forward planning horizon to address short-term reliability and market efficiency needs, which PJM describes herein as “short-term planning;” (ii) the six to 15 year analysis that PJM undertakes today to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development, which PJM describes herein as “intermediate-term planning;” and (iii) the NOPR’s proposed 20 year new long-term planning process, which PJM describes herein as “Long-Term Regional Transmission Planning” (the term the Commission uses in the NOPR)).

PJM thanks the Commission for making the commitment it made in the NOPR,¹⁴⁷ and urges that the Commission reaffirm in the Final Rule that the new Long-Term Regional Transmission Planning process is an add-on process, and does not change the existing short-term reliability and market efficiency planning processes.

2. PJM Generally Supports the Key Elements of the Commission’s Proposed Long-Term Scenario Planning, Except as Noted Herein

The key elements of the Commission’s proposed Long-Term Regional Transmission Planning process calls for transmission providers to conduct regional transmission planning by:

- using a 20-year time horizon (or longer) for Long-Term Scenario development¹⁴⁸ and reassessing those Long-Term Scenarios at least every three years;¹⁴⁹
- incorporating into those Long-Term Scenarios specific categories of Factors that may affect transmission needs driven by changes in the resource mix and demand;¹⁵⁰
- developing at least four “plausible and diverse” Long-Term Scenarios that reasonably capture probable future outcomes and make it possible to distinguish among the effects of distinct transmission facilities or distinct benefits for similar transmission facilities;¹⁵¹
- using “best available data;”¹⁵² and
- possibly identifying for inclusion in the Long-Term Scenarios geographic zones with strong potential for new generation resource development.¹⁵³

PJM comments on each of these elements below.

¹⁴⁷ NOPR at P 72.

¹⁴⁸ *Id.* at PP 92, 97.

¹⁴⁹ *Id.* at P 93.

¹⁵⁰ *Id.* at P 104.

¹⁵¹ *Id.* at P 123.

¹⁵² *Id.* at P 130.

¹⁵³ *Id.*

a. PJM Urges the Commission to Consider a 15-Year Planning Horizon to Avoid the Greater Level of Uncertainty Associated with a Mandatory 20-Year Time Horizon for Long-Term Scenario Development; PJM Supports an Assessment of those Long-Term Scenarios Every Three Years

The Commission proposes to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year planning horizon in order to “allow for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities.”¹⁵⁴ The Commission also proposes to require transmission providers reassess every three years whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and, if so, update the Long-Term Scenarios as needed.¹⁵⁵

As discussed below, PJM currently uses a 15-year transmission planning horizon in its existing RTEP process. While there is no crystal ball when it comes to transmission planning for the future, PJM continues to believe a 15-year planning horizon allow for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities while reducing input assumption risks associated with a 20-year horizon.¹⁵⁶

¹⁵⁴ *Id.* at PP 92, 97-98.

¹⁵⁵ *Id.* at P 97.

¹⁵⁶ *PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,114 (2019) (finding “PJM’s proposal to use the same 15-year planning period for evaluating all projects to be just and reasonable, given that the data for periods outside of the planning period are less accurate”).

1) PJM Believes a 15-Year Planning Horizon is More Appropriate than a 20-Year Planning Horizon

Background

A 15-year planning horizon allows PJM to determine transmission needs driven by load growth, capacity resource adequacy, generation resource integration, market efficiency, public policy and operational performance requirements. A 15-year planning horizon also allows transmission providers to consider many long lead-time transmission options,¹⁵⁷ and to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development across the PJM Region. In conducting the 15-year ahead analysis, PJM identifies any reliability violations on the PJM system that may require an upgrade for years 6 through 15. These long-term cases are used to evaluate the need for more significant projects requiring a longer lead-time to develop.

PJM's Experiences Confirm that a 15-Year Planning Period Is Appropriate

For the reasons set forth in its ANOPR Reply Comments, reiterated below, PJM continues to believe a 15-year planning horizon is appropriate. As PJM's Independent Market Monitor ("IMM") explained in responding to the ANOPR, "uncertainties faced by transmission planners include the entry of new generation, the retirement of old generation, changing patterns of congestion, load growth, fuel costs, fuel availability, power usage, the phasing out of old generation and transmission technologies and the introduction of new technologies, including technologies that may not yet be commercial or even exist, as well as new policies and programs

¹⁵⁷ Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels.

that can affect transmission planning inputs.”¹⁵⁸ This information becomes only more uncertain or unreliable the further out into the future it is forecasted.¹⁵⁹

Given the unpredictability of such assumptions, PJM believes it would not be appropriate for transmission providers to be required to adopt planning horizons longer than 15 years. Prior experiences support PJM’s position. For instance, less than 20 years ago, the Commission signaled its interest in developing regional transmission solutions to “facilitate fuel diversity including increased integration of coal-fired resources to the transmission grid.”¹⁶⁰ In a May 13, 2005 technical conference, (“May 2005 Technical Conference”), held in Charleston, West Virginia the Commission inquired, among other things, into:

[T]he current transmission planning efforts and public policy issues from a state and federal level, including how the current processes address the potential for coal power projects and the identification of obstacles to coal development.¹⁶¹

The Commission’s focus at the time was to encourage the development of new transmission from the coal fields of West Virginia and Kentucky to serve growing load in the mid-Atlantic region. PJM does not take a position on the merits of the issues the Commission was exploring in May 2005, but points to this proceeding to illustrate that policy goals can change radically over a very short period of time. Had RTOs focused on developing new transmission to support the

¹⁵⁸ *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Comments of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. RM21-17-000, at 2-3 (Nov. 11, 2021).

¹⁵⁹ PJM has found that the certainty and reliability of this information begins to decline around seven years out. Forecasting generator interconnection interest after seven years is speculative at best. Forecasting load – which is expected to grow again - will depend on certainty of electrification estimates. Today, available vendor/consultant data is at state-level, at best, in terms of granularity.

¹⁶⁰ *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Notice of Technical Conference, Docket No. AD05-3-000, at 1 (Feb. 16, 2004).

¹⁶¹ *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Second Supplemental Notice of Technical Conference, Docket No. AD05-3-000, at 2 (May 5, 2005).

further export of coal more than 15 years out, as the Commission explored back in 2005,¹⁶² customers would have paid for costly new transmission facilities that were totally at odds with the policy preferences of many states today.

Moreover, although all transmission provides some benefit, clearly the location of the proposed transmission lines to the coal fields would have been sub-optimal to meet the needs of renewable developers building wind projects in the Commonwealth Edison zone, in northern Ohio and along the mountain ridges of Pennsylvania and solar projects being built in New Jersey and North Carolina among other locations. Clearly, a longer planning horizon based on the Commission's 2005 inquiry would have yielded results that would have been very costly and not reflective of customer demand and would not have withstood the test of time.

Another example is the Potomac Appalachian Transmission Highline ("PATH") transmission backbone project that was based on projected load growth and included in the RTEP models. Specifically, based on analysis conducted in 2007, the PJM Board of Managers ("PJM Board") approved the Amos-Kemptown 765 kV transmission line, known as PATH. Load deliverability-driven reliability criteria violations were identified as early as 2012. When PJM conducted its analysis as part of the 2010 RTEP cycle, including review of proposed alternatives, the PJM Board reaffirmed the need for the PATH project as the most robust solution to address reliability criteria violations identified in 2015. PJM's 2011 RTEP analysis, however, projected slower rates of load growth for the short-term than had been seen in earlier load forecasts, which indicated that the need for the PATH project had moved out beyond 2015. Then, PJM's 2012

¹⁶² For example, at the May 13, 2005 Technical Conference, PJM spoke about a new initiative labeled Project Mountaineer that was being evaluated under PJM's RTEP process "to explore ways to further develop an efficient transmission super highway ... to deliver the low-cost coal resources in [the West Virginia region] to market." *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Transcript of Technical Conference, Docket No. AD05-3-000, at 61 (May 13, 2005).

RTEP analysis showed that all previously-identified NERC reliability criteria thermal and reactive violations were no longer observed in years through 2027; that is, PJM's 2012 analyses showed that reliability drivers no longer existed for the project throughout the 15-year planning horizon principally as a result of a notable decline in projected load growth and congestion.

In light of these changed circumstances, PJM staff recommended to the PJM Board that the PATH Project be removed from the RTEP. PJM staff explained that grid conditions changed since the line was originally planned, including changed load forecasts, generation additions and retirements, as well as increased reliance on demand response and energy efficiency programs. Due to these changed circumstances and the fact that updated analysis no longer identified reliability criteria violations within the 15-year planning horizon, the PJM Board formally removed the PATH project from the PJM RTEP on August 24, 2012.¹⁶³ In short, the volatility of input parameters cancelled the need for a \$1.8 billion transmission line identified in 2007, that was confirmed to be needed five years out in 2012, but by 2012 was no longer needed for at least another 15 years, if at all.

The above examples highlight that the dynamic nature of the transmission system, based on swings in economic forecasts, demand response, generation retirements, evolving public policies and fuel cost and availability, adding greater uncertainty to PJM planning studies at the 15-year time horizon. PJM therefore continues to believe moving to 20-year planning horizon will only add additional risk with little corresponding benefits, and that the currently-effective 15-year forward look-ahead is more appropriate as a just and reasonable long-term planning horizon.

¹⁶³ See <https://www.pjm.com/~media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx>.

2) PJM Believes it is Reasonable to Require Transmission Planners to Assess Long-Term Scenarios Every Three Years, Subject to Clarification

The Commission proposes to require transmission providers to update Long-Term Scenarios at least once every three years.¹⁶⁴ The Commission posits that a three-year frequency requirement appropriately balances transmission providers' need to reassess changes in the resource mix and demand with the burden of developing Long-Term Scenarios.¹⁶⁵

PJM generally supports the Commission's proposal to evaluate Long-Term Scenarios every three years to ensure the Long-Term Scenarios reflect recent forecasts of future system conditions. PJM does not believe that this exercise should merely involve "reassessing" the base case developed for the prior analysis. Rather, PJM would create a new base case based on transmission topology, Factors, as well as stakeholder inputs to reflect material changes to the system on a long-term basis. The point of this three-year assessment would be to make sure trends are analyzed in more than just one three-year period to determine whether any identified needs persist.

As the Commission notes, developing Long-Term Scenarios can be costly and time-consuming for transmission providers, states and stakeholders.¹⁶⁶ To that point, PJM requests that the Commission clarify that the three-year assessments must proceed in a serial, non-overlapping fashion. That is, the evaluation and development of Long-Term Scenarios should be completed within three years, and the next three-year evaluation and assessment of Long-Term Scenarios should not begin until the prior evaluation and development has been completed. The three-year

¹⁶⁴ NOPR at PP 97, 99.

¹⁶⁵ *Id.* at P 99.

¹⁶⁶ *Id.* at P 93.

clock is predictable and PJM estimates the entire process (Long-Term Scenario development, Long-Term Scenario analysis, open window, project selection, cost allocation, Board approval) will take three years.

b. PJM Generally Supports the Proposed Long-Term Scenario Development Factors, Subject to the Concerns Expressed Below

The Commission proposes to require transmission providers to incorporate, at a minimum, seven specific categories of factors to help identify transmission needs driven by changes in the resource mix and demand (“Factors”),¹⁶⁷ and incorporate them into the development of Long-Term Scenarios.¹⁶⁸ The Commission further proposes to require that transmission providers give all interested stakeholders, including States, a meaningful opportunity to propose Factors to be considered in the development of such Long-Term Scenarios.¹⁶⁹

1) PJM Generally Supports the Proposed Factor Categories

As PJM explains above, it has engaged in discussions with its stakeholders about how PJM could identify, from among an array of future scenarios, the scenarios upon which its transmission planners could rely to justify moving forward with directives to build new transmission. Specifically, in the Master Plan White Paper,¹⁷⁰ PJM proposed a series of decision-making criteria

¹⁶⁷ Specifically, the Commission proposes that transmission providers incorporate the following seven categories of Factors into the development of Long-Term Scenarios: “(1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.” NOPR at P 104 (footnotes omitted).

¹⁶⁸ See NOPR at PP 104-108.

¹⁶⁹ *Id.* at P 109.

¹⁷⁰ See Appendix C, PJM Master Plan White Paper.

that could be utilized to sort future possible scenarios into actionable forecasts of future needs that could then provide a reasoned and well-documented justification for a directive to build new transmission.¹⁷¹ PJM also proposed the following list of factors that it could consider to expand upon the assumptions PJM currently uses in developing its long-range planning solutions:¹⁷²

- Electric load trends in the residential, commercial and industrial areas;
- State & federal policy;
- documented input on state plans to meet policy;
- Documented record of customer needs developed through surveys and other means; customer survey trends and goals (including identification of existing and potential future PPA sources, DER plans of local governments, etc.);
- Future generation interconnections, including input from states considering siting concerns;
- Future generation deactivations/retirements; and
- Interregional transfers and criteria.

PJM notes that the factors it proposed in its Master Plan White Paper generally align with the seven Factors proposed by the Commission in the NOPR. PJM supports the use of the NOPR's proposed Factors to develop Long-Term Scenarios, and generally agrees with the specific Factors proposed by the Commission, subject to the discussion in Section II.A.2.b(2), below.

2) PJM Believes the Commission Should Direct Transmission Providers to Include Additional Factors, and Has Some Concerns About Certain Elements of the Factors Proposed in the NOPR

As stated, PJM generally supports the proposed Factors, but provides the following proposals for the Commission's consideration.

¹⁷¹ PJM Master Plan White Paper at i-v.

¹⁷² *Id.* at v.

1. Adding Enhanced Reliability Planning and Interregional Coordination as Factors

First, for the reasons explained in Sections II.A and III.F, PJM strongly believes that the Commission should direct transmission providers to include Enhanced Reliability Planning¹⁷³ and Interregional Transfer Capability¹⁷⁴ as factors to consider when developing Long-Term Scenarios as follows:

- **Enhanced Reliability Planning** – PJM provided specific recommendations as to what should be included under the category of resilience (or, as PJM rebrands the term here, as “Enhanced Reliability Planning”) in response to the Commission’s RTO/ISO Resilience Docket.¹⁷⁵ Enhanced Reliability Planning includes such activities as: (i) removing CIP-014 facilities from the critical facilities list; (ii) consideration of specific enhanced reliability criteria focused on development of plans for maximum credible events under NERC TPL-001-4 (referred to as “extreme events”) standard; and (iii) direct cataloging and development of plans to proactively improve resilience of the grid based on an updated loss of load criteria standard. Accordingly, PJM proposes the Commission add an eighth Factor to the list for consideration as follows: “(8) identified needs to enhance the reliability of the grid including, but not limited to storm hardening of critical facilities, reducing the number of critical CIP-014 facilities through transmission upgrades, coordination of infrastructure development with natural gas pipelines serving generation in the region and ensuring redundancy of facilities where appropriate, to address the threat of physical or cyberattacks.”
- **Interregional Transfers and Criteria** – PJM provided recommendations that the Commission drive the development of a robust standardized minimum interregional transfer capability methodology that would inform future interregional transmission coordination to help ensure that there is adequate transfer capability between regions, so as to enhance both reliability and resilience as the nation faces more extreme weather and other related challenges. PJM recommends that the Commission move forward with a transmission planning driver that would recognize the value of interregional transfer capability, including development of a standard methodology (and planning driver to support transmission expansions to meet that methodology) in an effort to evaluate an appropriate level of import/export capability that supports a larger more reliable and resilient grid.¹⁷⁶ Accordingly, PJM proposes the Commission add a ninth Factor to the list for consideration as follows: “(9) the application of future interregional transfer capability”

¹⁷³ See Section II.A, *supra*.

¹⁷⁴ See Section III.F, *infra*.

¹⁷⁵ See n.59, *supra*. See also Appendix B.

¹⁷⁶ See Section III.F, *infra*.

methodologies to be determined by a subsequent Commission Order after consultation with the Department of Energy national laboratories and industry stakeholders.”

PJM views these factors as key components of forward-looking, Long-Term Scenario planning to meet transmission needs driven by “changes in the resource mix and demand.”¹⁷⁷

2. Utilizing Customer Data and Probabilistic Planning in the Long Term Process

Second, as PJM outlined in its Initial and Reply ANOPR Comments,¹⁷⁸ as well as in the PJM Master Plan White Paper, PJM continues to believe that long-term transmission planning should be informed by: (i) customer surveys and documentation of customer-identified needs; (ii) consideration of federal and state public policy requirements; and (iii) consideration of probabilistic planning.

3. Providing Flexibility by Avoiding “Over-Tariffing” the Process

Third, PJM cautions the Commission against imposing prescriptive requirements regarding the development of factors that would complicate region-specific efforts to promote more efficient and cost-effective regional transmission planning and development. Multi-state RTOs, like PJM, need regional flexibility to: (i) develop consistent regional methods to determine which Factor input data makes the most sense to their respective regional planning processes, and (ii) determine the degree to which each factor is incorporated into each Long-Term Scenario power flow model. PJM, and indeed all entities, should not be required to “over-tariff” the number, definition, and process associated with implementing seven distinct Factor categories.¹⁷⁹

¹⁷⁷ In addition to the specific language describing these two additional Factors set forth above, PJM also proposes in Appendix A language to reflect that transmission providers include nine categories of Factors for consideration. See Appendix A at 6.

¹⁷⁸ See PJM Initial ANOPR Comments at 27-41; PJM ANOPR Reply Comments at 7-10.

¹⁷⁹ See also Section II.B, *supra*.

4. Modifying the Requirement to Consider Local Laws and Regulations

Fourth, PJM notes that multiple proposed Factors incorporate local laws, local regulations and/or local goals.¹⁸⁰ PJM believes, however, that requiring transmission providers to locate and catalog all possible local laws, regulations and/or goals in regional, long-range transmission planning creates an unreasonable compliance obligation, as well as a resource drain. The PJM Region covers all or parts of 13 States and the District of Columbia. It is not practical or efficient for PJM to be expected to research, track and maintain data about the laws, regulations and goals set in the myriad of individual counties, towns, municipalities, cities, townships and villages across the PJM footprint. Further, local laws and regulations tend to change rapidly based on prevailing local politics, and it would be extremely difficult and time consuming to ensure that PJM's data on these issues is up to date. Not only that, local laws, regulations and/or goals are likely to conflict within the locales own county or state, as well across PJM's diverse footprint, and it is unclear how PJM would consider conflicting policies in its factors.

PJM therefore recommends that the Commission only require transmission planners to consider local laws, local regulations and/or local goals to the extent that such local laws or regulations that are explicitly brought to PJM's attention by states, stakeholders, or other local regulators. That is, PJM respectfully requests that the Commission clarify that the burden to ensure that a transmission planner is aware of any local laws, local regulations and/or local goals that should be considered is on states, stakeholders, or other local regulators, not on the transmission planner.

¹⁸⁰ See NOPR at PP 106, 108.

5. Addressing the Confidentiality Concerns with Prognosticating Specific Generation Retirements

Finally, PJM notes that the Commission proposes to require transmission providers to consider resource retirements when developing its planning assumptions for its regional transmission planning process.¹⁸¹ PJM supports engaging in economic impact analyses of generation resource retirements and doing so in a transparent manner.

Nevertheless, the Commission must recognize that publicly releasing information as to specific generators at risk of retirement, and then building new transmission based on that prognostication, has direct market as well as plant workforce impacts. Such public releases could drive disinvestment in generation units to the extent that transmission is built to move generation as if the plant were no longer operational. Moreover, the impact on the workforce of a generating plant cannot be ignored as laborers seek to square the transmission planner's analysis with management's pronouncements and the terms of labor agreements. Further, once the transmission case is released, this information will be apparent so there is no practical way to mask the specific generation units that the transmission planner has deemed to be shut down by a specific date.

PJM has already engaged over the years in planning for "at risk" generation and supports both the need to do so and the heightened transparency and public process set forth in the NOPR. However, PJM raises these issues as the Commission will need to provide clear direction on how it wishes to address them in its drive toward greater transparency and consultation, especially since masking of data is not a practical solution once the transmission case is released.

¹⁸¹ NOPR at P 104 & n.193. The Commission proposes to grant transmission providers flexibility in how they incorporate this Factor into Long-Term Scenarios, provided that they identify and publish specific Factors for each of these categories. *Id.*

3) PJM Supports Allowing States and Stakeholders to Provide Input Regarding the Factors Used to Develop Long-Term Scenarios

PJM supports the Commission’s proposal to provide for an open and transparent process in order to give States and stakeholders the opportunity to offer input regarding the Factors to be considered in the development of Long-Term Scenarios.¹⁸² In fact, PJM already has standing committees in place that would be the appropriate place for such discussions.¹⁸³ The TEAC, in particular, offers stakeholders an open, transparent public forum to provide advice and recommendations throughout the development of the RTEP. PJM also conducts stakeholder meetings through three Subregional RTEP Committees (Mid-Atlantic, Western and Southern). These three Subregional RTEP Committees review proposed upgrades of more local concerns.¹⁸⁴

Moreover, state consultation mechanisms are currently being utilized in the development of the RTEP. Specifically, PJM amended Schedule 6 of the Operating Agreement to include input from the Independent State Agencies Committee (“ISAC”).¹⁸⁵ PJM facilitates periodic meetings with the ISAC to discuss: (i) the assumptions used in performing the evaluation and analysis of potential transmission needs; (ii) regulatory initiatives, if appropriate; (iii) the impact of regulatory actions and other trends in the industry; and (iv) alternative sensitivity studies, modeling

¹⁸² *See id.* at PP 110-111.

¹⁸³ PJM’s stakeholder processes were found by the Commission to satisfy its Order No. 890 and Order No. 1000 openness principles through PJM’s open and transparent planning committees. *See PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,163, at P 28 (2008), *order on compliance*, 127 FERC ¶ 61,166 (2009), *order on reh’g*, 129 FERC ¶ 61,177 (2009) (Order No. 890 Compliance Orders) and *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 52 (2013) (PJM’s 2013 Order No. 1000 Compliance Order).

¹⁸⁴ The Subregional RTEP Committees are open to all interested parties and meet regularly to review local transmission needs on below 230 kV facilities prior to finalizing the Local Plan that is integrated into the RTEP. *See* Operating Agreement, Schedule 6, section 1.3.

¹⁸⁵ The ISAC was formed via unanimous resolution by the Organization of PJM States, Inc. (“OPSI”), which officially endorsed the formation of an Independent State Agencies Committee. *See* OPSI Charter at <https://opsi.us/wp-content/uploads/2020/10/ISAC-Charter-10.1.20.pdf>.

assumption variations and scenario analyses proposed by the ISAC. At such meetings, PJM also discusses the status of the RTEP study process, including any input received from the TEAC and Subregional RTEP Committees. PJM also informs the TEAC and Subregional RTEP Committees of the input received from the ISAC. ISAC's input is considered in developing the range of assumptions to be used in the studies and scenario analyses of the potential enhancements and expansions to the RTEP. Although PJM had previously engaged with its state commissions, this amendment to its RTEP process memorialized PJM's commitment to meet regularly with state representatives (not limited to state commissions) in order to encourage greater input from the states and to better integrate individual state needs into the regional plans.

PJM conducts its tariffed regional planning process by first developing the study scope and assumptions to be used in identifying system needs.¹⁸⁶ Following identification of system needs, PJM reviews proposed solutions and vets the selection and recommendation of proposed solutions with the TEAC for review and comment before presenting the recommended plan to PJM's independent PJM Board of Managers for review and approval.¹⁸⁷ The TEAC is also involved in review of project modifications¹⁸⁸ and annual reevaluation of market-efficiency projects.¹⁸⁹

c. PJM Believes that it is Reasonable for the Commission to Direct Transmission Providers to Use at Least Four Plausible and Diverse Long-Term Scenarios, Subject to the Conditions Described Below

The Commission proposes to require each public utility transmission provider to develop, as a lower bound, at least four distinct Long-Term Scenarios based on the Factors described above

¹⁸⁶ Operating Agreement, Schedule 6, sections 1.5.2-1.5.4, 1.5.6(b), (d); 1.5.7(a), (c)(i)-(iii).

¹⁸⁷ *See id.*, sections 1.5.7(c)(iii), 1.5.8(d) and 1.6.

¹⁸⁸ *Id.*, section 1.5.8(k).

¹⁸⁹ *Id.*, section 1.5.7(f).

(as well as any additional Factors adopted by the region).¹⁹⁰ The Commission does not propose to require transmission providers to study specific types of Long-Term Scenarios or assess the likelihood of each Long-Term Scenario actually occurring, so long as each Long-Term Scenario is “plausible” and “diverse.”¹⁹¹ At least one of the four Long-Term Scenarios, however, must account for a “high-impact, low-frequency event” such as extreme weather events or cyber-attacks.¹⁹² Finally, the Commission proposes that the use of probabilistic transmission planning or stochastic techniques could satisfy this requirement.¹⁹³

1) PJM Supports the Requirement that Transmission Planners Use Multiple Planning Long-Term Scenarios, But Believes the Commission Should Grant Transmission Planners the Flexibility to Analyze More or Fewer Long-Term Scenarios Based on Stakeholder Input

PJM supports the Commission’s proposal to require transmission providers to develop an array of future scenarios that transmission planners could use to justify moving forward with directives to build new transmission. PJM believes that the Commission should encourage transmission planners to utilize four Long-Term Scenarios to develop the Long-Term Regional Transmission process, but allow individual transmission planners flexibility to develop more or fewer Long-Term Scenarios. Any decision to use more or less than four Long-Term Scenarios would be vetted with states and other stakeholders to ensure an open and transparent process.

¹⁹⁰ NOPR at PP 121-122. The Commission also offers guidance on how transmission providers could effectively develop Long-Term Scenarios, suggesting that providers create a base case, most-likely-to-occur scenario, and then create alternative scenarios with different assumptions that are less likely to occur. NOPR at P 123.

¹⁹¹ *Id.* at P 123. The Commission further proposes that transmission providers explain on compliance how their process will identify a plausible and diverse set of Long-Term Scenarios. *Id.*

¹⁹² *Id.* at P 122.

¹⁹³ *Id.* at P 124.

In Section III.A.2.b, above, PJM discusses the Factors that it believes should be considered to create the different Long-Term Scenarios used to plan new transmission that is focused on customer needs while both ensuring that the reliability and resilience of the grid is maintained, and that there is not an unreasonable shift of costs or risks to end-use customers. The choice of which Long-Term Scenarios to use should be: (i) based on a clearly defined, robust set of Factor development criteria grounded in a record of customer needs and interests within the planning horizon; (ii) capable of adapting to an evolving set of future system conditions; and (iii) crafted to foster the appropriate level of transmission expansion.

PJM agrees that, given uncertainty associated with identifying system needs 15 or 20 years out, it is prudent to develop multiple Long-Term Scenarios, with different sets of plausible assumptions. In its Master Plan White Paper, PJM described how it would propose to implement scenario-based transmission planning.¹⁹⁴ At a high level, Long-Term Scenarios would be developed by defining input parameters and associated thresholds based on a set of drivers (the NOPR refers to these as “Factors”). Predefined study criteria would then be applied to a plausible subset of Long-Term Scenarios. PJM describes its proposed scenario-based transmission planning process, and includes an example of how drivers, scenario development criteria and scenario study criteria could work together to address a specific resilience issue, in the Master Plan White Paper included herein as Appendix C.

For purposes of a Long-Term Regional Transmission Planning process, PJM could envision utilizing four Long-Term Scenarios as follows:

¹⁹⁴ See Appendix C, Mater Plan White Paper at pages iii-viii.

- Long-Term Scenario Study No. 1 – Low uncertainty – known inputs per formal notice such as legislative and regulatory laws, announced deactivations and load forecasts;
- Long-Term Scenario Study No. 2 – Medium uncertainty – legislative and regulatory “goals” and economic retirement analysis;
- Long-Term Scenario Study No. 3 – High uncertainty – speculative, aspirational dimension of input factors; and
- Long-Term Scenario Study No. 4 – High-Impact-Low-Frequency (“HILF”) resilience evaluation.

PJM believes that employing multiple Long-Term Scenarios, including one that includes a base case, most-likely-to-occur scenario, as well as additional scenarios that demonstrate a wider range of possible transmission needs, is a prudent way to ensure transmission providers properly account for changes in the resource mix and demand without overbuilding system needs. However, given the diversity among regions, PJM believes it is appropriate to allow transmission planners to work with their states and stakeholders within their respective regions to determine the appropriate number of and specific scenarios to be used in the Long-Term Regional Transmission Planning process.

2) PJM’s Use of Probabilistic vs. Deterministic Analyses to Develop Long-Term Scenarios

The Long-Term Scenario development criteria will specify the parameters to consider for each Long-Term Scenario driver, determine how the various drivers should be considered in relationship to one another, and determine which of the various Long-Term Scenarios should be selected. The Long-Term Scenario study criteria will provide the methodology by which the Long-Term Scenario is analyzed as well as the decision-making process that determines whether the Long-Term Scenario study results warrant the addition of a new, or the removal of approved, transmission expansion. Criteria for selecting which Long-Term Scenarios will trigger the need for transmission expansions can be either deterministic or probabilistic. In practice, there will need to be some combination of the two given that certain variables and assumptions in Long-

Term Scenario development, and triggers for new transmission expansions, may more naturally align with a probabilistic approach and others with a deterministic approach.

For example, PJM annually assigns generation in the PJM interconnection queue a probability factor that the proposed generation will achieve commercial operation. Such statistics could be used to develop metrics that quantify the probability of a transmission need. A similar statistic could be developed for future generator deactivations based on the history of the unit's participation in the various PJM markets, information as to whether the unit's costs are covered under long-range contracts or state legislative programs, and the "net revenue" analysis undertaken by the IMM. However, other variables in the planning process, such as state and federal policies, appropriate levels of interregional transfers, and certain extreme events, may lend themselves more to a deterministic approach.

PJM envisions that an approach that can trigger transmission expansions based on both probabilistic and deterministic considerations will be necessary to properly account for the myriad of different variables that need to be considered in a robust, long-term transmission expansion planning process. This criteria and associated thresholds will need to be well defined and vetted with stakeholders. Ultimately, the decision-making criteria will be designed to support a transparent, repeatable transmission planning process that values the above information as well as stakeholder and policymaker input.

As the RTEP process moves from the long-term, to intermediate, to short-term timeframe, Long-Term Scenarios associated with each subsequent timeframe should be informed by the evolution of identified trends.

d. PJM Agrees with the Recommendation that Long-Term Scenarios Should Be Based on “Best Available Data Inputs”

The Commission proposes to require transmission providers to use “best available data inputs,” or “data inputs that are timely and developed using diverse and expert perspectives, adopted via a process that satisfies the transparency planning principle . . . , and that reflect the list of factors that public utility transmission providers must incorporate into Long-Term Scenarios.”¹⁹⁵ The Commission also seeks comments on whether it should facilitate or otherwise standardize the best available data inputs that meet this proposed requirement.¹⁹⁶

PJM supports the requirement that transmission providers be required to use best available data input in the development of Long-Term Scenarios. Indeed, PJM’s existing short-term and intermediate-term planning analyses currently incorporate the latest and best available information regarding load forecasts, generating resources, transmission topology, demand resources and bilateral transactions.¹⁹⁷ PJM also supports the Commission’s statement that it is not intending to imply “that there is a single ‘best’ value for each data input,” but rather that transmission providers use best practices to develop that data input.¹⁹⁸ This affords transmission providers the flexibility needed to establish a well-defined, repeatable process that is described in detail in PJM manuals and supports the Commission’s goal that the Long-Term Regional Transmission Planning process comply with the transparency planning principle.

¹⁹⁵ NOPR at P 130. The Commission explains that the “transparency planning principle requires public utility transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Public utility transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies.” NOPR at n.226.

¹⁹⁶ *Id.* at P 134.

¹⁹⁷ See PJM, *Manual 14B: PJM Region Transmission Planning Process*, §§ 1.3, 2.3, Attachment B and Attachment H (rev. 51, Dec. 15, 2021).

¹⁹⁸ NOPR at P 130.

PJM would support the Commission holding forums to discuss best practices and development of additional data sources. These forums should be informational in nature and allow planners to share information without taking on the more formal litigation-focused Technical Conference format. PJM also believes that the Commission should consider use of existing interconnection-wide organizations such as the Eastern Interconnection Planning Collaborative and the Western Electricity Coordinating Council to host some of these forums.

e. PJM Does Not Support the NOPR's Proposal to Require Transmission Providers to Identify Geographic Zones

The Commission proposes to require transmission providers to identify geographic zones with the potential for large amounts of new generation.¹⁹⁹ The Commission states that this proposal is intended to assist developers and transmission providers in coordinating their activities to make investments in geographic areas likely to experience large amounts of new generation.²⁰⁰ PJM is concerned that the geographic zone requirement proposal would obligate transmission planners to draw lines on a map 20-years forward through the long term planning process. This process could well prove arbitrary and inflexible when an approach that is more tailored to information coming out of the marketplace, including interconnection requests, would be better anchored to specific marketplace information and the nearer term decisions of interconnection customers. Accordingly, PJM sets forth below an alternative more case-specific flexible approach that builds on and is better synchronized with the interconnection process and market

¹⁹⁹ *Id.* at P 145.

²⁰⁰ *Id.* at P 146. The Commission proposes a three-step process whereby transmission providers would have to consider whether to: (i) identify specific geographic zones within the transmission planning region that have potential for large amounts of new generation development based on meteorological, geophysical, and other data regarding energy potential; (ii) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (iii) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios. NOPR at P 145.

developments, and accommodates topologies as diverse as those in PJM versus those in far less dense regions of the nation.

1) PJM Could Support a Region-Specific Assessment of Geographic Clusters to Identify Transmission Needed to Plan for Changes in the Resource Mix and Demand

In its ANOPR Initial Comments, PJM provided data demonstrating that the majority of current in-service generation and queued, future generation projects in PJM (most of which are renewable resources)²⁰¹ are geographically located 100 miles or less from its densely-populated and highly-networked major metropolitan areas and electrically close to load centers.²⁰² This is in contrast to other areas of the country – *e.g.*, MISO, SPP, CAISO, and ERCOT – where distances can exceed 100 miles. And, unlike those regions, PJM’s footprint does not generally encompass large swaths of land to where trunk lines could be built to access new renewable generation resources. As the Commission acknowledges in the NOPR, multi-state RTOs like PJM “may face unique challenges and differing energy policy interests or preferences” regarding the establishment of geographic zones.²⁰³ In short, not all regions face the same challenge of accessing geographic areas attractive to development of renewables that are remote from load centers.

²⁰¹ As of November 30, 2021, PJM had 215,000 MW of renewable projects in its interconnection queue (or approximately 94% of the MW in the queue). *See* ANOPR Reply Comments at 23.

²⁰² *See* ANOPR Initial Comments at 9-10 (demonstrating that of the 691 renewable generation projects currently in-service, 613 generation projects (88.7%) are geographically located 100 miles or less from load centers, 74 generation projects (10.7%) are geographically located between 101 miles to 200 miles from load centers, and only four generation projects (0.6%) are geographically located more than 200 miles from a load center); *id.* at 10-11 (demonstrating that of the 1,826 planned generation projects currently in the PJM interconnection queue, 1,560 planned generation (85.4%) projects are located geographically 100 miles or less from load centers, 254 planned generation projects (13.9%) are geographically located between 101 miles to 200 miles from load centers, and only 12 planned generation projects (0.7%) are geographically located more than 200 miles from a load center). *See also id.* at 12-13 (setting forth the results of the Electrical Distance Test, which demonstrates that future interconnection queue projects are not more distant from load centers as compared to current in-service generators and that, in fact, they are electrically closer).

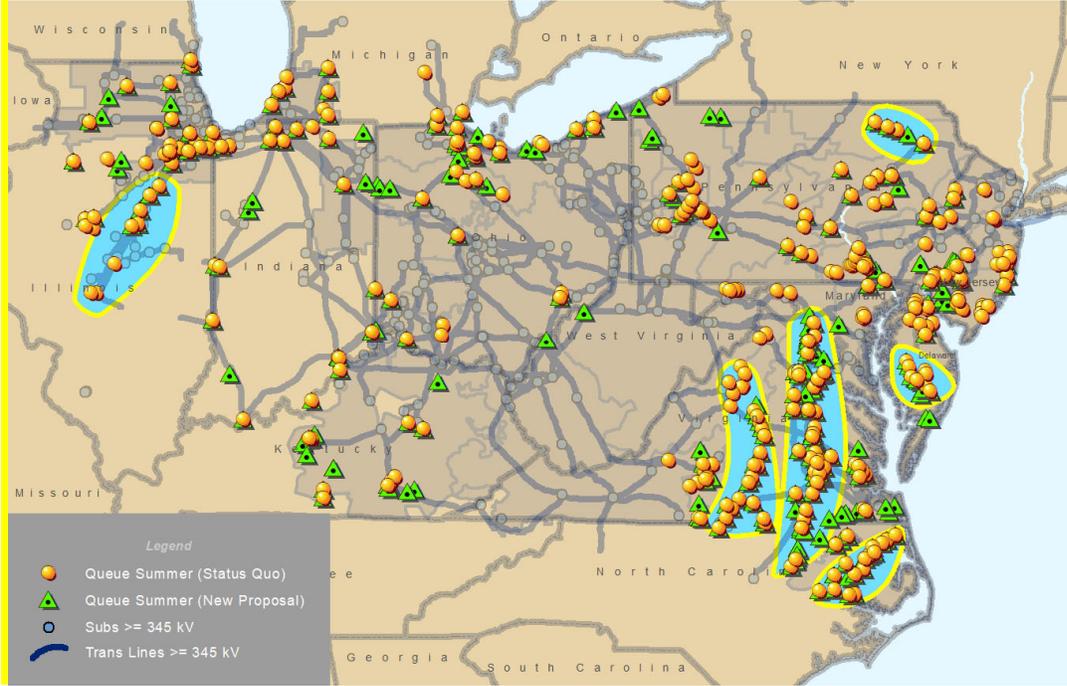
²⁰³ NOPR at P 152.

For each of these reasons, although geographic zones and affirmative obligations to build out to those zones in an ERCOT or CREZ-type model may be appropriate in some regions, PJM has not lacked requests for interconnection, as the PJM system today allows for reasonable access to the existing transmission network as relevant to where renewable interests currently exist. That said, as part of a Long-Term Regional Transmission Planning process, PJM could assess whether clusters of generation interconnection requests could drive more robust transmission solutions to interconnect greater numbers of generation resources at once. This information would then be presented to states which could, under PJM's State Agreement Approach process,²⁰⁴ approve a more robust build (and arrive at a cost-sharing arrangement as between interconnection customers and the state(s)).

PJM offers **Map 1** below to demonstrate why regional variance makes sense rather than prescriptive zones in the context of a Final Rule. The map demonstrates approximate location of reliability violations stemming from queued generation interconnection studies, primarily renewables, in the PJM interconnection queue. The map highlights (in yellow circles) clusters of reliability criteria violations driven by queued generation. This means that for a regional system topology as densely networked as PJM, the interconnection queue itself reveals geographic areas attractive to developers of renewable generation and, consequently, areas of general focus for Long-Term Regional Transmission Planning scenario studies for determining potential transmission need that could be planned, developed and constructed in a prudent and orderly manner.

²⁰⁴ See Operating Agreement, Schedule 6, section 1.5.9.

Map 1. Potential Future Overloads Driven by Generation Interconnection Requests



If each developer’s individual interconnection request triggered a need for interconnection-related network upgrades, its respective incremental addition of power to existing transmission lines could lead to piecemeal development along the lines about which the Commission has expressed concern.²⁰⁵ In order to address this concern, as part of a Long-Term Regional Transmission Planning process, PJM could assess whether there are clusters of generation interconnection requests that will move forward to determine whether there is the potential for more robust transmission solutions to interconnect greater numbers of resources at once.²⁰⁶

²⁰⁵ See, e.g., NOPR at P 26.

²⁰⁶ PJM stresses the importance of requiring developers of proposed generators to establish site control as part of the initial interconnection application. This will help to better ensure the viability of the strength of the resource based on the unaffiliated recommended locations with the likelihood to obtain siting. PJM’s currently-effective interconnection rules and the proposed revisions to the interconnection rules each require generator developers to establish site control at the time of the interconnection requests. See PJM, *Manual 14G: Generation Interconnection Requests*, § 2 (rev. 7, Oct. 20, 2021).

Second, and related to the point above, in its currently-pending Interconnection Process Reform Filing,²⁰⁷ PJM proposes to simplify the analysis of cost responsibility for certain required network upgrades from individual projects by clustering projects within the same cycle.²⁰⁸ Under PJM's proposal, PJM will determine the minimum amount of required network upgrades required to resolve each reliability criteria violation in each cycle by studying the impact of the projects in the cycle in their entirety, and will identify the interconnection requests in the cycle that contribute to the need for the required network upgrades.²⁰⁹ Each interconnection request that contributes to the need for a network upgrade will receive cost allocation for that upgrade pursuant to its contribution to the reliability violation.²¹⁰ PJM anticipates that clustering interconnection requests in this manner will encourage clusters in a given queue to move forward together, which will in turn lead to a greater likelihood of transmission upgrades of more expansive scope thereby increasing ability to deliver greater amounts of renewable generation.

Third, PJM's existing State Agreement Approach process is another methodology pursuant to which PJM can assess whether there are clusters of generation for which it may be necessary to build transmission in order to accommodate a changing resource mix and demand. The State Agreement Approach is a mechanism to incorporate a state's public policy goals into PJM's RTEP by enabling a state, or group of states, to propose to sponsor a transmission solution to effectuate its public policy requirements, provided that the state(s) agrees that its customers will pay 100%

²⁰⁷ *PJM Interconnection, L.L.C.*, Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (June 14, 2022) ("Interconnection Process Reform Filing").

²⁰⁸ *See* Interconnection Process Reform Filing at 61. A clustered cycle is a group of projects that are studied together in a single study, rather than on an individual basis in serial fashion based on the order in which the projects entered the queue. *See id.* at n.11.

²⁰⁹ Interconnection Process Reform Filing at 61.

²¹⁰ *Id.*

of the related transmission costs. After New Jersey became the first state to use the SAA process in November 2020,²¹¹ PJM filed a SAA Study Agreement with the Commission,²¹² pursuant to which PJM opened a competitive window to solicit transmission solutions to accommodate New Jersey’s goal to bring up to 7,500 MW of offshore wind generation online by 2035.²¹³ The State Agreement Approach process is thus a way to address transmission development needs, based on policy requirements that PJM will incorporate in the RTEP process.

Fourth, PJM has previously conducted targeted planning studies to determine the extent to which transmission facilities that could present a more efficient and economic path for states to achieve their clean and renewable energy policy objectives than if each state integrated its offshore wind generation completely independent of one another. For instance, in October 2021, PJM issued its Offshore Wind Transmission Study: Phase 1, a PJM-wide reliability study to determine reinforcements to the onshore grid to reliably deliver not only the 14,268 MW of then-announced offshore wind in the PJM region, but also to achieve all state Renewable Portfolio Standards targets

²¹¹ See *PJM Interconnection, L.L.C.*, New Jersey State Agreement Approach Study Agreement, SA No. 5890, Docket No. ER21-689-000 (Dec. 18, 2020) (“December 2020 Filing”) (accepting a State Agreement Approach Study Agreement between the NJ BPU and PJM (“SAA Study Agreement”). The SAA Study Agreement was accepted by the Commission, effective November 18, 2020. *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,090 (2021). The SAA Study Agreement provides for coordination between PJM and the State of New Jersey to ensure that the PJM Transmission System can accommodate New Jersey’s public policy goal of procuring 7,500 MW of offshore wind generation by 2035.

²¹² *PJM Interconnection, L.L.C.*, Rate Schedule FERC No. 49, Docket No. ER22-902-000, New Jersey State Agreement Approach Agreement by and Among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities (Jan. 27, 2022) (“SAA Filing”). In the SAA Filing, PJM submitted for filing an executed State Agreement Approach Agreement between PJM and the New Jersey Board of Public Utilities, designated as Rate Schedule FERC No. 49 (the “SAA Agreement” or “Agreement”). The Commission accepted the SAA Agreement on April 14, 2021. See *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024 (2022) (“SAA Agreement Order”), *reh’g denied*, 179 FERC ¶ 62,131 (2022).

²¹³ In parallel, the New Jersey Board of Public Utilities has been conducting a series of solicitations to acquire offshore wind generation. The competitive window closed in September 2021, and PJM is currently in the process of analyzing and reviewing the project proposals. Once proposals from transmission developers have been evaluated through the PJM planning process, and following consultation with PJM, the State of New Jersey (through the NJ BPU) has the option (but is not required) to select one or more of the proposed projects that it finds the more efficient or cost effective solution to meet its public policy goals. 2021 State Agreement Approach Process Guidance Document (Sept. 24, 2021), <https://www.nj.gov/bpu/pdf/ofrp/SAA%20Process%20Overview.pdf>.

in the PJM region by determining the necessary renewable capacity by resource type and location.²¹⁴ PJM believes such targeted planning studies are another way PJM could assess potential geographic clusters to identify infrastructure that may be necessary to plan for transmission needs of anticipated future generation to meet a changing resource mix and demand.

Finally, while PJM does not currently utilize heat maps for planning purposes, PJM supports the idea of heat map development. PJM proposes that heat maps should be developed with the assistance of national labs, and should be used as a tool to provide insight for identifying favorable locations based upon various economic, environmental or geographic factors.

The initiatives discussed above could be used to assess potential areas where transmission may be needed to accommodate anticipated future generation to meet a changing resource mix and demand. Although PJM has discussed with states and stakeholders options to “right size” upgrades in locations where there are multiple interconnection requests, the Commission should not, through the NOPR, drive a solution based on geographic zones where other more practical, efficient and lower cost solutions might work in a region such as PJM. Nor should PJM be forced to address through compliance a proposal which, as demonstrated based on the evidence set forth in PJM’s ANOPR comments and above,²¹⁵ is not an effective approach in the PJM Region for meeting the Commission’s goals.

²¹⁴ See PJM Interconnection, L.L.C., Offshore Wind Transmission Study: Phase 1 Results (Oct. 19, 2021), available at: <https://www.pjm.com/-/media/library/reports-notice/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx>.

²¹⁵ See n.202, *supra*.

2) PJM Does Not Believe Transmission Providers Should Be Responsible for Assessing Generation Developers' Commercial Interests

The Commission proposes to require transmission providers to develop a method to assess a generation developer's commercial interest in developing generation within a designated geographic zone. PJM does not support the Commission's proposal to require transmission providers to assess generation developers' commercial interests based on the factors set forth in the NOPR,²¹⁶ which the Commission suggests can be relied upon as evidence of commercial interest in developing generation within the zone. PJM is not in a position to speculate on siting viability, financial integrity, or the other variables that drive developer business planning. This requirement is especially problematic to projects 15 or 20 years forward. Based on PJM's interconnection queue experience, the data PJM receives from developers is often premised on a commercial in-service date of less than seven years forward, and would provide little value for developing Long-Term Scenarios 15 or 20 years out in the future.

More fundamentally, it is simply unrealistic to require a transmission planner to make assumptions as to decisions made in Boardrooms of a host of independent entities and then use those guestimates as a basis to plan and direct the construction of new transmission. Such prognostications would simply not prove sustainable when subject to cross examination in a state siting proceeding.

Although PJM does not support basing an assessment of developers' commercial interest on the criteria proposed in the NOPR, PJM would support a more flexible process that would address uncertainties inherent to long-term transmission planning by allowing transmission

²¹⁶ See NOPR at P 150.

planners to more confidently take into account future customer trends and needs, along with policy developments.²¹⁷ Specifically, PJM would support a requirement that transmission planners develop a region-specific process that allows transmission planners to develop a record of customer trends and needs, through surveys and other means, to document customers' purchasing plans. This could include, for example, surveys about plans to enter into long-term power purchase agreements to meet corporate sustainability or developing distributed resources through municipal or private aggregation. This alternative would still be speculative on a 15- or 20-year forward basis, but would provide more of a record to support the choice of Long-Term Scenarios. Moreover, it would avoid forcing transmission planners to prognosticate on individual interconnection customers' withdrawal decisions, and then apply that prognostication 15 or 20 years forward as a basis to support new transmission builds as the NOPR presently directs.

B. PJM's Comments on Additional Elements of the Long-Term Regional Transmission Planning Process

1. The Commission's Proposal to Require Transmission Builds Based on Withdrawals of Interconnection Requests Invites Gaming. PJM Believes a More Targeted Case-Specific Approach to Aligning Transmission Build-Outs Associated with Multiple Interconnection Requests at a Single Location on the Grid, as well as the Reforms Proposed in PJM's Interconnection Process Reform Filing, Will Better Address the Commission's Concern

Although the ANOPR identified a wide scope of possible reforms, including reforms to the generator interconnection process,²¹⁸ the NOPR proposes narrow interconnection-related revisions that seek to align the interconnection and long-term regional planning processes by requiring that transmission needs identified through interconnection queue processes are considered in regional

²¹⁷ See PJM ANOPR Initial Comments at 41-46

²¹⁸ See ANOPR at PP 150-158.

transmission planning processes.²¹⁹ Specifically, the NOPR proposes to require transmission providers to consider proposed transmission facilities in the regional planning process if those facilities would address interconnection-related needs that: (i) have been identified in at least two queue cycles in the past five years; (ii) require an upgrade of at least 200 kV or have an estimated cost of at least \$30 million; (iii) have not been developed due to request withdrawals; and (iv) are not slated for address by an upgrade in an executed agreement (or in an agreement the developer requested to be filed unexecuted).²²⁰

PJM urges the Commission to decline to implement the NOPR’s Network Upgrade Proposal, as PJM believes the proposal creates perverse incentives for generation developers, and would result in undue discrimination. Instead, as discussed below, PJM believes that the concerns the Commission is attempting to address through the Network Upgrade Proposal can be addressed by a more targeted, case-specific approach to aligning transmission build-outs associated with multiple interconnection requests at a single location on the grid and, in PJM’s case, its region-specific interconnection queue reform proposal that is currently pending before the Commission.²²¹

²¹⁹ See NOPR at PP 166-174. PJM notes that the Commission recently issued a separate Notice of Proposed Rulemaking seeking comments on proposed reforms to its *pro forma* large and small interconnection procedures set forth in transmission providers’ Open Access Transmission Tariffs. *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (2022) (“Generator Interconnection NOPR”). PJM will be filing separate comments on the Generator Interconnection NOPR.

²²⁰ NOPR at P 166. PJM refers to this proposal is herein as the “Network Upgrade Proposal.”

²²¹ *PJM Interconnection, L.L.C.*, Tariff Revisions for Interconnection Process Reform, Docket No. ER22-2110-000 (June 14, 2022) (“Interconnection Process Reform Filing”). In the Interconnection Process Reform Filing, PJM proposes revisions to significantly improve the process by which new and upgraded generation resources connect to the grid.

a. The Commission Should Decline to Require Implementation of the Network Upgrade Proposal

PJM does not support the proposal to “require that transmission providers consider regional transmission facilities that address certain interconnection-related needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s)....”²²² PJM believes the Commission should decline to require implementation of this proposal for several reasons.

First, the Network Upgrade Proposal is premised on the Commission’s assumption that interconnection customers are “withdrawing their interconnection request in the face of significant costs associated with interconnection-related network upgrades.”²²³ At least with respect to PJM, however, the Commission’s assumption that an interconnection customer’s “sticker shock” at the cost of interconnection-related network upgrades is the “deciding factor” for the customer’s decision to withdraw from the interconnection queue²²⁴ is not correct. In PJM, projects withdraw from the interconnection queue for a myriad of business reasons that frequently have little, if anything, to do with cost of transmission network upgrades. In fact, PJM has seen generators without significant upgrade needs that never reach commercial operation. For instance, over the past six years, several dozen projects that had executed Interconnection Service Agreements (“ISAs”) and with requirements less than \$5 million nonetheless terminated their ISAs and did not reach commercial operation.

²²² NOPR at P 165.

²²³ *Id.* at P 166.

²²⁴ *See id.* at P 162.

PJM does not frequently see projects in its interconnection queue that have interconnection studies identifying the need for network upgrades of greater than \$30 million.²²⁵ In considering its response to the Network Upgrade Proposal, PJM performed an analysis of the Dominion Zone, in which PJM received more than 700 generator interconnection requests since the beginning of the AA1 queue in May 2014, through the close of AG1 queue in September 2020. Fourteen interconnection queue submittals required network upgrades at 500 kV – a voltage level for which network upgrades would most likely incur costs greater than \$30 million – and also withdrew. Nine of the 14 withdrew before a Feasibility Study was issued, which would have provided the initial potential requirements for any upgrades and costs. Two that had reached the System Impact Study Phase required network upgrades of less than \$30 million prior to withdrawing from the queue. Three that had reached the System Impact Study Phase required network upgrades greater than \$30 million prior to withdrawing.

On the other hand, at least 20 projects in the Dominion Zone in queues AA1 through AG1, require 500 kV network upgrades (again, the voltage level for which network upgrades would most likely incur costs greater than \$30 million) and have not withdrawn to date. Nine of the 20 projects that have reached the System Impact Study Phase require 500 kV network upgrades greater than \$30 million and would interconnect four or more generators.

PJM acknowledges that withdrawn projects make up a significant portion of total interconnection request activity. PJM notes, however, that generation developers are not required to submit to PJM the reasons why they withdraw their interconnection requests from the queue. And, while generation developers seldom offer any reasons for their withdrawal, some developers

²²⁵ See *id.* at P 166.

have at times pointed to land issues and other permitting requirements as challenges to project construction and completion. Additionally, PJM's experience with long-time developers since the inception of the RTEP process in 1997 indicates that withdrawals reflect ongoing business decisions by developers in response to not only interconnection costs, but also to changing public policy and other regulatory issues, as well as siting, industry, fuel, economics, and any combined impact of those factors on project financing.

Second, PJM does not support the Network Upgrade Proposal, because it would create perverse incentives for generation developers to game the interconnection process to their advantage. A generator developer could submit multiple requests, knowing that significant network upgrades would be needed, then withdraw and trigger this Long-Term Regional Transmission Planning process step, shifting cost responsibility to load to pay for generator interconnection request-driven system expansion. Even though PJM's interconnection proposal has proposed affirmative steps to weed out speculative submittals,²²⁶ there still remains a considerable advantage for a developer to submit a request, pay the required deposits and then withdraw late in the process given the prospect that it might be able to shift the costs of the needed upgrades to load. Valid, viable long-term planning should not be based on reactionary behavior to the interconnection queue, regardless of the number of cycles in which an upgrade may or may not have appeared.

Finally, PJM believes the Network Upgrade Proposal could lead to undue discrimination. The interconnection process is designed to send economic signals to generation about where to locate in terms of network upgrade costs. The Network Upgrade Proposal would, in effect, shift

²²⁶ Interconnection Process Reform Filing at 52-55.

upgrade costs that are ostensibly too high for generation developers from generation to load if such a process trigger were to be implemented as proposed in the NOPR.

b. A More Targeted, Case-Specific Approach to Aligning Transmission Build-Outs Associated with Multiple Interconnection Requests and Reforms Proposed in PJM's Interconnection Process Reform Filing Can Help Alleviate the Concern the Commission is Attempting to Address Through the Network Upgrade Proposal

The Commission opines that five years is the appropriate starting point to track when interconnection-related network needs are identified, because it will limit the scope of the Network Upgrade Proposal to interconnection-related needs that are: (i) likely to persist, (ii) are not unique to a single interconnection customer's request, and (iii) have the potential, if evaluated through the Long-Term Regional Transmission Planning process, to provide more widespread benefits to transmission customers.²²⁷ PJM believes, however, that other reforms would accomplish the same end without creating the perverse developer incentives described above.

For instance, PJM believes that a more targeted approach to identifying the need for transmission could be based on demand, as identified by the interconnection queue and state policies. Under this approach, states could voluntarily take responsibility for funding network upgrades based on their renewable portfolio goals. States that have high renewable portfolio standards ("RPS") goals and wish to develop a "backbone system" that could ensure the most delivery of these renewables to meet their aggressive goals could consider this approach, depending on the level of costs and the relative efficiencies of such a backbone system, as opposed to individual upgrades, in meeting their RPS targets. PJM envisions that implementation of this proposal could include the following:

²²⁷ NOPR at P 170.

- Network upgrades that exceed a certain dollar threshold could be presented to states for their consideration as to whether they wish to underwrite these costs under the State Agreement Approach;²²⁸
- Network upgrades with 10 or more interconnection projects impacting the same facility are provided to the state with an option for the state to support the funding of at least a portion of the network upgrades through assessment to load; or
- Generators that have impacts on the facility reimburse the state under the terms and conditions set forth in an agreement under the State Agreement Approach process.

Additionally, PJM believes that its pending Interconnection Process Reform Filing will help address the concerns identified by the Commission in the NOPR.²²⁹ If accepted, the Interconnection Process Reform Filing will comprehensively reform PJM’s interconnection procedures, and will include several elements that are designed to create a faster, more efficient process that provides more actionable analysis results and better cost certainty. Among other things, through the Interconnection Reform Filing, PJM proposes to move to a “first-ready, first-served” approach that reviews proposals and assigns upgrade costs in clusters.²³⁰ This change is designed to streamline the study process, reduce restudies, and reduce cost allocation disputes.²³¹ And, while overall required network project costs do not change, cost responsibility shifts such that one project does not bear all the risk, potentially offering a better opportunity for more interconnection requests to move forward out of a given queue cycle.

²²⁸ See Operating Agreement, Schedule 6, section 1.5.9.

²²⁹ The Commission states that it is concerned that when interconnection customers withdraw from the interconnection queue, the identified interconnection-related network upgrades remain unbuilt and the related transmission needs go unaddressed. The Commission therefore proposes the Network Upgrade Proposal to “allow for the consideration of transmission facilities to meet interconnection-related needs repeatedly identified in the generator interconnection process....” NOPR at 165.

²³⁰ See PJM Interconnection Reform Filing at 1-2.

²³¹ *Id.*

PJM believes this could help to address the Commission’s concern that developers’ “sticker shock” at the cost of interconnection-related network upgrade is leading to queue withdrawals, identified interconnection-related network upgrades remaining unbuilt, and potential transmission capability need unaddressed.

2. PJM Supports an Evaluation of the Benefits Associated with Transmission Facilities to Address Long-Term Needs Driven by Changes in the Resource Mix and Demand

The Commission proposes several reforms related to identifying and quantifying benefits of transmission facilities that address needs driven by changes in the resource mix and electricity demand.²³² The Commission includes a list of benefits that could be considered to reasonably capture the benefits of transmission facilities that meet identified needs, but emphasizes that it is not proposing to require transmission providers to use any specific benefits or calculate those benefits in a particular manner.²³³ The Commission further proposes to require transmission providers to evaluate benefits over at least a 20-year time horizon, starting from the estimated in-service date of the transmission facilities.²³⁴ PJM discusses these proposals below.

a. PJM Proposes to Evaluate Five Categories of Benefits Specific to the PJM Region and that the Commission Set a Core Set of Benefits to be Considered Nationwide

The Commission expresses concern that by only evaluating benefits specific to a particular category of transmission need for purposes of determining whether a regional transmission facility

²³² See NOPR at PP 183-225, 227-230 and 233-235.

²³³ Rather than adopting a particular definition of “benefits” or “beneficiaries,” the Commission proposes a list of 12 benefits in the NOPR to consider, including: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity. See NOPR at PP 183-225.

²³⁴ NOPR at P 227.

meets the criteria for selection, currently-effective regional transmission planning and cost allocation processes fail to account for all of the benefits that transmission facilities could provide.²³⁵ The Commission is further concerned that failing to account for the benefits that transmission built to address transmission needs driven by changes in the resource mix and demand may lead to needed transmission facilities not being built, thus adversely affecting ratepayers.²³⁶

PJM agrees that assessing a broader set of benefits as part of a Long-Term Regional Transmission Planning process could demonstrate the greater value that regional, more holistic transmission development could provide. PJM therefore supports the Commission's proposal to require transmission providers to consider an expanded set of benefits when evaluating transmission facilities to address long-term needs driven by changes in the resource mix and demand. However, PJM believes that there is significant overlap among the 12 categories of benefits that the Commission has proposed for consideration. Instead, PJM describes below five consolidated categories of benefits that PJM would propose to consider specific to the PJM Region, including how PJM proposes to quantify the benefits in each category.

Additionally, while PJM agrees that transmission providers should have flexibility to propose which benefits make sense to consider for their own regions,²³⁷ PJM believes the Commission should adopt a core set of benefits to be considered nationwide in order to ensure consistency across the country.

²³⁵ *Id.* at P 67.

²³⁶ *Id.*

²³⁷ *Id.* at P 186.

As an Illustration of their Application, PJM Proposes Specific Benefit Categories to be Considered for the PJM Region

PJM seeks flexibility in the application of the benefits to a given region. PJM outlines below its current thinking on which of the benefits it would seek to analyze for the PJM region. PJM outlines this list in order to underscore the need for flexibility in the Final Rule concerning benefit analysis as well as to lay the foundation for certain benefits, as outlined below, which PJM believes should be considered by all transmission providers across the nation.

- **Enhanced Reliability Benefit**: As discussed earlier, PJM believes that any endeavor to tackle the transmission needs of the electric grid of the future would be incomplete without factoring Enhanced Reliability²³⁸ into revisions to intermediate- and long-term regional transmission planning. To that end, PJM proposes to consolidate two of the Commission’s proposed benefit categories: #6 (mitigation of extreme events and system contingencies) and #7 (mitigation of weather and load uncertainty).²³⁹ This benefit would evaluate the ability of grid enhancements selected pursuant to the Long-Term Regional Transmission Planning process to serve load reliably under extreme events and vulnerabilities, like those caused by weather, in terms of Value Of Lost Load (“VOLL”) but for the upgrade. While not a new concept, PJM notes that VOLL implementation would require significant stakeholder engagement to define how to quantify such benefit.
- **Avoided or Deferred Reliability Transmission Projects and Aging Infrastructure Replacement**: As the Commission explains, this category would consider reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.²⁴⁰ Specifically, when certain transmission projects are proposed to address changes in the resource mix and demand, transmission upgrades that would otherwise have to be made to address reliability needs or replace aging facilities may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the incremental cost of the Long-Term Regional Transmission facility. In order to assess the value of this benefit, PJM proposes that, once a facility is identified through the Long-Term Regional Transmission Planning process, PJM would reach out to the relevant transmission owner(s) to ascertain whether there are opportunities to make efficient use of existing rights-of-way, including replacement or enhancement to existing transmission lines that may already be on such rights-of-way. If so, PJM could develop an estimate of the extent to which such replacement or enhancement

²³⁸ As set forth above, PJM proposes to define “Enhanced Reliability” as “[t]he ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.”

²³⁹ NOPR at P 185.

²⁴⁰ *Id.* at PP 185, 189-190.

would be less costly than a new greenfield transmission facility. Opportunities could include, by way of example, a new configuration or towers, new cable, or a second circuit in an existing double circuit construction.

- **Deferred Capacity Investment**: For this category, PJM proposes to consolidate two of the Commission’s proposed benefit categories: #2 (reduced loss of load probability or reduced planning reserve margin) and #9 (deferred generation capacity investments).²⁴¹ As part of this combined category, PJM would consider whether the proposed transmission facility: (i) would reduce the cost of needed generation capacity investments by deferring generation investment needs in resource-constrained areas by increasing the transfer capabilities and (ii) can reduce the frequency and severity of necessary load curtailments by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. PJM would have to work with its stakeholders to develop a methodology to quantify benefits associated with deferred capacity investment on both a regional and state-by-state basis.²⁴²
- **Production Cost Savings**: As part of this category, PJM would consider whether investment in a proposed Long-Term Transmission Facility would result in a reduction of production costs.²⁴³ Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. PJM has significant experience with quantifying benefits associated with production cost savings as part of its RTEP near-term planning market efficiency benefit/cost analysis.
- **Net Load Payment Savings**: “Net Load Payment Savings” was not a benefit proposed by the Commission in the NOPR. However, given PJM’s unique regional market structure, PJM believes it would be useful to consider and quantify this benefit category. This benefit is sourced in the expectation that the system would be planned and operated in an economically efficient manner, therefore all loads are having equal access to lower-cost suppliers. Net load payments savings are defined as the product of load megawatts and the Locational Marginal Price (“LMP”) at a particular location minus the corresponding value of transmission rights. This benefit is realized when additional transfer capability created by transmission projects allows for suppliers that have lower incremental costs of production displace higher-cost suppliers and decrease the LMPs. From a market perspective, net load payment savings benefit reflects the reductions in unhedged

²⁴¹ *Id.* at P 185.

²⁴² PJM has already explored ways to assess the benefits associated with reduced loss of load probability or reduced planning reserve margin. See The Benefits of the PJM Transmission System (Apr. 16, 2019), available at: <https://pjm.com/-/media/library/reports-notice/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en> (“PJM Benefits of Transmission White Paper”).

²⁴³ NOPR at P 185.

congestion as load zones will be able to access lower-cost suppliers otherwise inaccessible to them due to transmission constraints. In consequence, the net load payments benefit provides support for funding transmission upgrades aiming to decrease congestion, thus giving the downstream load access to the lower-cost generation located upstream from a transmission constraint. To that end, load payment savings benefit is more suitable for solving localized issues than production cost savings that makes most sense for large systems where benefits accrue regionally. In other words, it is more difficult to see production cost benefit on local basis as load serving entities in deregulated market environment do not see production cost, *per se*, load just sees load payments reflective of LMPs.

Core Benefits that PJM Believes Should Be Considered Nationwide

PJM lists above the benefit metrics that it supports considering as part of a PJM-specific Long-Term Regional Transmission Planning process. Although PJM recognizes that regional flexibility may be necessary to address each region's specific needs and market structures, PJM nonetheless proposes that in order to enhance Interregional Coordination and interconnection-wide Enhanced Reliability, a limited but common set of benefits should be considered nationwide and therefore addressed specifically in the Final Rule.

PJM believes this common set of benefits can aid in discussions among transmission planners about interregional projects and enhance the overall reliability of the Interconnection while avoiding some regions potentially "leaning" on other stronger regions within the Interconnection. PJM proposes that of the categories it proposes for its own region above, that the following benefit categories should be considered on a nationwide basis: (i) Enhanced Reliability; (ii) Avoided or Deferred Reliability Transmission Projects and Aging Infrastructure Replacement; (iii) Deferred Capacity Investment; and (iv) Production Cost Savings.

b. PJM Cautions the Commission that Requiring Evaluations of Transmission Benefits to Be Considered Over a 25-28 Year or Longer Time Horizon Will Be Speculative At Best

As indicated above, the Commission proposes to require transmission planners to evaluate the benefits of regional transmission facilities to meet these needs over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.²⁴⁴ Given the average amount of time it takes to build new transmission facilities,²⁴⁵ PJM wishes to clarify that calculating a benefit metric over a 20-year horizon from the in-service year of the selected facility would essentially require transmission providers to look out approximately 25-28 years into the future. For the reasons described above regarding the uncertainty associated with a 20-year or longer Long-Term Planning Horizon,²⁴⁶ any analysis of benefits on a 25-28 years forward-looking basis will be speculative at best. The above dynamic nature of the transmission system, based on swings in economic forecasts, demand response, generation retirements, evolving public policies and fuel cost and availability, add greater uncertainty to any benefits analysis using a 25 to 28-year time horizon.

²⁴⁴ NOPR at P 227.

3. PJM Believes the NOPR’s Proposed Selection Process for Regional Transmission Facilities Requires Clarification in Order to Avoid Increasing Uncertainty and Litigation that Could Slow the Development of Needed Transmission Infrastructure

a. The NOPR’s “Proposed Reform” Concerning Selection Criteria Contains a Number of Provisions which are Unclear and May Be Premised on a Set of Expectations Concerning Long-Term Regional Transmission Planning that May Not Be Practical

The language in the NOPR speaks of “transmission facilit[ies] *identified* as part of Long-Term Regional Transmission Planning.”²⁴⁷ This use of the term “identified” in the definition of Long-Term Regional Transmission Facilities confuses, rather than clarifies, the class of facilities for which a tariffing of decision criteria and cost allocation is required on compliance. For starters, the word “identified” is not defined in this context and, as a result, raises certain questions as to what is intended, such as:

- If a transmission need appears in one or more Long-Term Scenarios in the long-term process, but no specific project is actually ordered so far in advance, is that project considered a Long-Term Regional Transmission project once it is actually ordered in the near-term?
- Is there an immediate obligation upon issuance of the Final Rule to establish a cost allocation and selection criteria before transmission providers have had a chance to implement the Long-Term Scenario planning process for Long-Term Regional Transmission Planning processes?

Thus, PJM finds that despite the NOPR’s attempt at clarity, it is unclear whether and when a transmission provider that identifies needs under Long-Term Scenarios must select a Long-Term

²⁴⁵ See PJM, *Manual 14B: PJM Region Transmission Planning Process* (rev. 51, Dec. 15, 2021) (Upgrades The outcome of the long-term deliverability analysis will identify the need to include in the RTEP any: New 230 kV or 345 kV circuits to support load growth in years 6 through 8, Right-of-way acquisition for any new 230 kV or 345 kV circuits to support load growth in years 9 and 10, New 500 kV or greater circuits to support load growth in years 6 through 12).

²⁴⁶ See Section III.A.2.a, *supra*.

²⁴⁷ NOPR at P 252, n.398.

Regional Transmission Facility, if at all.²⁴⁸ In fact, the NOPR specifically qualifies that identification and evaluation of transmission facilities is for “potential selection” in the regional transmission plan,²⁴⁹ and nothing more.

If the Commission intended the new compliance directive to require transmission providers to re-justify selection criteria and cost allocation to apply to *all* projects included in a regional transmission plan, including existing short-term planning processes, because the facility was developed using a modicum of information or trends “identified” in the Long-Term Regional Transmission Planning process, but not actually chosen twenty years forward, then the breadth of the compliance obligation to tariff upon issuance of the Final Rule selection criteria and a cost allocation sweeps in and potentially requires *de novo* re-litigation of existing near-term selection criteria and cost allocations that were developed with stakeholders and states.²⁵⁰

In addition, PJM believes that the proposal to require immediately upon compliance the tariffing of detailed selection criteria and cost allocation to be tied to “transmission facilities *selected* in the regional transmission plan for purpose of cost allocation through Long-Term Regional Transmission Planning”²⁵¹ is premature, and presupposes that the proposed Long Term

²⁴⁸ While it does not necessarily appear to be the case, if the Commission intends the new compliance directive to require transmission providers to re-justify selection criteria and cost allocation to apply to *all* projects included in a regional transmission plan, including near-term planning processes, because the facility was developed using a modicum of information or trends “identified” in the Long-Term Regional Transmission Planning process, but not actually chosen twenty years forward, then the terms of this NOPR belie what is a much more sweeping and disruptive process that could at a minimum blur, or more disturbingly upend, the existing near-term selection criteria and cost allocations that were developed with stakeholders and states.

²⁴⁹ NOPR at PP 68, n.128, 125, 126, 241, 244 and 250.

²⁵⁰ While PJM recognizes the need to have clear cost allocation rules for regional transmission facilities in order to develop transmission facilities determined by the transmission provider to meet the region’s needs, PJM is simply stating that before requiring such rules upon initial compliance, the Commission allow transmission providers time to develop and gain experience with the Long-Term Scenario process in order to develop, with input from stakeholders and states, and propose appropriate selection criteria and cost allocation, if necessary, to meet the goals of this NOPR.

²⁵¹ NOPR at P 243 (emphasis added).

Regional Transmission Planning process will immediately result in the selection of specific projects 15 or 20 years into the future.

While large transmission projects can take many years to build,²⁵² it is not evident, at least for a region like PJM where existing and new generation are located close to load centers given the densely configured nature of the network,²⁵³ that a host of new projects identified under the Long-Term Regional Transmission Planning process will be “selected” – or in the words of the proposed Final Rule “identified” – 15 to 20 years forward, at least not initially.²⁵⁴ PJM urges the Commission to avoid making the compliance process more challenging than it needs to be by requiring an immediate tariffing of selection criteria and a cost allocation for the class of projects “identified” in the Long-Term Regional Transmission Planning process before that process has even been developed and transmission providers have had an opportunity to gain experience by actually launching the process and working with stakeholders and states on improvements and course corrections as necessary.

To that end, instead of requiring transmission providers, on initial compliance, to propose selection criteria and cost allocation for projects that may in the future be chosen for inclusion in the regional transmission plan based on the results of the Long-Term Scenario evaluation, the Commission should provide for a phased-in approach that directs transmission providers to first develop their Long-Term Scenario planning processes before requiring tariffing selection criteria and cost allocation for any “potential” projects that may be selected out of the Long-Term Regional Transmission Planning process.

²⁵² See Section II.A.2.c(2), *supra*.

²⁵³ See n.202, *supra*.

²⁵⁴ NOPR at P 252, n.398.

Furthermore, given the lack of clarity in the NOPR’s proposal for the selection of facilities under the Long-Term Regional Transmission Planning process, the Commission should be careful not to inadvertently require wholesale revisions to the existing near-term planning criteria and cost allocation methods developed after years of stakeholder input.²⁵⁵ If the selection criteria for the Long-Term Regional Transmission Planning process are not carefully defined, the line could begin to blur as to which projects are needed to address near-term reliability and market efficiency issues, and which were identified through the Long-Term Regional Transmission Planning process and bring into question the development of needed transmission in the near- and intermediate-terms²⁵⁶ while cost allocation is re-litigated once again.

Consequently, the Final Rule must clearly delineate between a need that is subject to the near- and intermediate-term planning processes and a need under the Long-Term Regional Transmission Planning process, particularly because the NOPR proposes that the Long-Term Scenarios developed within the proposed 20-year planning horizon are to be “reassessed and revised every three years, with each such re-assessment providing the basis for identification and evaluation of transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.”²⁵⁷

Similar to the lack of clarity as to the scope of the compliance requirement detailed above, if the selection criteria requirements includes reassessment every three years of any need that has any possible tie to the Long-Term Scenarios developed in the Long-Term Regional Transmission

²⁵⁵ As noted below, although there remain elements of cost allocation still subject to litigation, the fundamental components of cost allocation for short- and intermediate-term reliability and market efficiency projects in the PJM Region have been settled through agreements in which states were heavily involved. *See* Section III.C, *infra*.

²⁵⁶ *See* n.4, *supra*, noting that the term “intermediate” is intended to address the existing long-term planning processes covering studies 6 through 15 years.

²⁵⁷ NOPR at P 68, n.128.

Planning process, it is not clear how the Commission squares this new compliance directive with its stated intention not to disturb existing near-term reliability and market efficiency planning criteria and cost allocation frameworks.²⁵⁸ Instead of reconciling this potential conflict, the NOPR seems to confuse the distinction.

If the NOPR proposes to require an extended re-evaluation process to justify selection criteria and cost allocations for projects that may have had some genesis in information “identified” in the Long-Term Scenarios considered in the Long-Term Regional Transmission Planning process, it potentially throws open the entirety of the planning process to costly and unnecessary re-litigation. PJM is concerned that in addition to being difficult to track and implement, this NOPR could have far-reaching ramifications in terms of compliance and implementation.

Finally, in Section II.A.2 of these Comments, PJM urges the Commission to avoid a repeat of Order No. 1000’s lengthy and inconsistent implementation of its terms among regions, particularly non-RTO regions. Given what appear to be inconsistencies with other sections of this NOPR, the proposals in this section also have the potential to be misinterpreted or misunderstood, or applied in different regions in radically different ways. If not clarified, any next rule could result in a repeat of the problems experienced in complying with Order No. 1000.

b. Given the NOPR’s Lack of Clarity on the Selection of Regional Transmission Facilities, PJM Submits the Following Recommendations for Clarification

PJM believes that, as written, the “selection criteria” directives are inconsistent with the Commission’s stated goal elsewhere in the NOPR that the Long-Term Regional Transmission

²⁵⁸ *Id.* at PP 8, 72.

Planning process is, in addition to the existing short-term planning processes, designed to better inform, without changing, those near-term processes especially those related to reliability and market efficiency planning.²⁵⁹ As a result, PJM submits the following recommendations specific to selection criteria:

- Make clear that “a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation” applies to projects *specifically chosen* for inclusion in the regional plan twenty years forward. It is conceivable that such projects would be ordered as a product of the proposed twenty-year process. However, the Final Rule should not trigger a wholesale re-litigation of cost allocation and planning criteria for any project ordered in the short-term simply because one or more scenarios undertaken in the long-term process prognosticated a *potential need* to be monitored, but not a need certain enough to drive selection of a transmission project in the new Long-Term Regional Transmission Planning process. Otherwise, the compliance directive could effectively trigger a re-litigation of *all* existing planning criteria and cost allocation given the blurriness of what constitutes a tie to the Long-Term Scenarios that would trigger the application of new selection criteria and cost allocation.
- Reaffirm in the Final Rule the Commission’s stated commitment in the NOPR to not disturb existing nearer-term reliability and market efficiency cost allocations and processes. Although these short-term processes will certainly benefit from and be informed by and benefit from the development of Long-Term Scenarios, the Final Rule should not trigger re-litigation of cost allocation and selection criteria for the short- and intermediate-term planning processes. Any such re-litigation will inevitably slow and create greater uncertainty in planning for these needed short-term projects.²⁶⁰
- Make clear that although consultation with the states and stakeholders is a key part of the proposed Long-Term Regional Transmission Planning process (and already is addressed through Order Nos. 890 and 1000 for the near-term planning processes), at the end of the day, at least for reliability and market efficiency projects, the transmission planner must remain the entity responsible (and accountable) for selecting the more efficient or cost-

²⁵⁹ See *id.* at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”).

²⁶⁰ In Section II.A of these Comments, PJM recommends a Commission directive that all transmission planners, for their planning beyond the five-year horizon, include more specific planning for enhanced reliability of the grid. That request is focused on enhancing existing intermediate-term planning, but does not, unlike potential interpretations of the selection criteria section, upend all of the existing and settled selection criteria and cost allocations associated with the intermediate-term planning process.

effective project consistent with the criteria set forth by the Commission in Order Nos. 890, 1000 and any Final Rule coming out of this process.

Additionally, in recognizing the important role played by the states in Long-Term Regional Transmission Planning to address the region's needs driven by changes to the resource mix and demand, the Commission proposes to require transmission providers to coordinate with the relevant state entities in developing selection criteria.²⁶¹ While PJM supports providing additional opportunity for involvement by states and the broader stakeholder membership in the Long-Term Regional Transmission Planning process, particularly as states and stakeholders take a more active role in helping to shape the long-term transmission needs driven by changes in the resource mix and demand, PJM must be able to develop criteria in the event states and the broader stakeholder membership are unable to agree.²⁶² Therefore, any requirement that transmission providers must demonstrate on compliance that they developed their proposed selection criteria in consultation with relevant state entities and the broader stakeholder membership in their respective planning regions must include the capability to demonstrate an inability to secure agreement.

²⁶¹ Under PJM's current planning process, PJM coordinates with its states through the Independent State Agencies Committee in the sharing of information required by PJM in its preparation of RTEP studies. *See* Operating Agreement, Schedule 6, section 1.5.4(c). In addition, Schedule 6 of the Operating Agreement provides for periodic meetings with PJM state entities through the Independent State Agencies Committee to discuss, among things: (i) assumptions to be used in performing the evaluation and analyses for the potential enhancements and expansions to the Transmission System; (ii) regulatory initiatives; (iii) the impact of regulatory actions; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by the Independent State Agencies Committee. *See* Operating Agreement, Schedule 6, section 1.5.6(d).

²⁶² NOPR at PP 241, 244.

4. Although PJM Believes that Dynamic Line Ratings and Advanced Power Flow Control Devices Are Useful Operational Tools, PJM Does Not Believe They Should be Viewed as Complete Substitutes for the Need to Develop New Transmission To Address Long-Term Needs

The Commission proposes to require transmission providers to more fully consider, in both near-term and long-term regional transmission planning and cost allocation processes,²⁶³ two specific grid-enhancing technologies: dynamic line ratings (“DLRs”) and advanced power flow control (“APFC”) devices.²⁶⁴ For each identified transmission need, the Commission proposes to require that project selection include consideration of whether a facility that incorporates these technologies would be more efficient and cost-effective,²⁶⁵ and to require the transmission planner to detail for stakeholders why or why not DLR and APFC devices were incorporated into selected regional transmission facilities.²⁶⁶

Although DLR and APFC devices are tools that can currently be considered by PJM, in select instances – including in operations and to inform short-term horizon market efficiency planning solutions²⁶⁷ – they are not interchangeable substitutes for the need to develop new transmission infrastructure to address long-term transmission needs focused on reliability. While the Commission asks transmission planners to “consider” whether selecting transmission facilities that incorporate these devices may offer a more efficient or cost-effective alternative to other

²⁶³ *Id.* at P 274.

²⁶⁴ *Id.* at PP 272-277.

²⁶⁵ *Id.* at P 273.

²⁶⁶ *Id.* at P 276.

²⁶⁷ PJM outlines the promising potential for deployment of DLR technologies to address operational issues both in these Comments and its Comments in Docket No. AD22-5-000. *See Implementation of Dynamic Line Ratings*, Motion for Leave to Comment and Comments of PJM Interconnection, L.L.C., Docket No. AD22-5-000 (May 9, 2022).

transmission facilities,²⁶⁸ PJM is concerned that the NOPR is premised on a view that DLR and APFC devices could serve as acceptable long term solutions that would obviate the need to build transmission facilities to solve grid enhancement needs identified through the Long-Term Regional Transmission Planning process.

In this area, words do matter, as do the signals that the Commission intends to send. Although PJM recognizes that the NOPR only requires *consideration* of these devices,²⁶⁹ the public's expectations need to be tempered so as to avoid an inference that DLR and APFC devices can serve as long-term substitutable solutions to meet system reliability needs. Failure to do so (while still embracing the operational promise of DLRs and APFC devices) will only further complicate the siting process and fan public opposition to the need for new transmission to meet reliability and market efficiency needs.

a. PJM Recognizes the Value of DLRs and APFC Devices as Operational Tools

Grid-enhancing technologies can help to enhance the capacity utilization, efficiency and safety of the transmission system, and give electric utilities and system operators more control over the grid. For instance, DLR is a tool of near real-time optimization that addresses thermal line limits by adjusting thermal ratings based on actual weather conditions including ambient temperature and wind, in conjunction with real-time monitoring of resulting line behavior. APFC devices can help to control the flow of power through a line and ensure flows remain within the applicable line rating by pushing power off overloaded lines or pulling power onto underutilized lines. APFC devices do not create new thermal capacity to the transmission lines, rather they can

²⁶⁸ NOPR at P 274.

²⁶⁹ *Id.* at P 273.

maximize the utilization of their thermal capacity by managing flows. In these ways, DLRs and APFC devices ultimately provide additional flexibility and serve as promising tools to system operators to assist with the safe and reliable operation of the grid. On the other hand, both DLR and APFC devices add complexities to system operations, as they require continuous monitoring and adjustments to fully utilize their benefits especially if deployed in large amounts throughout the system.

DLRs and APFC devices can also serve as a helpful tool to inform market efficiency planning and operations.²⁷⁰ PJM acknowledges that the use of DLRs and APFC devices could be considered as potential solutions to market efficiency driven projects, but only after gaining operational experience that demonstrates in real-time how they behave. Moreover, additional work is needed to ensure that a large number of these facilities (and the amount of data that would need to be processed in real time) could be operationally managed without negatively impacting the day-to-day system operational duties.

PJM continues to engage in discussion with interested parties in deploying DLRs and APFC devices. In October 2020, PJM and one of its Transmission Owners, PPL Electric Utilities Corporation (“PPL”), began to pilot the use of DLR sensors on three transmission lines to determine if the devices could alleviate congestion and provide PJM with real-time information to optimize the performance and increase actual power flow (not just static ratings).²⁷¹ Although the

²⁷⁰ PJM’s market efficiency planning process specifically considers non-transmission alternatives. *See* Operating Agreement, Schedule 6, section 1.5.8(b) (“Following identification of existing and projected limitations on the Transmission System’s physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Operating Agreement, Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, and prior to evaluating potential enhancements and expansions to the Transmission System, the Office of the Interconnection shall publicly post on the PJM website all transmission need information, including violations, system conditions, and economic constraints, and Public Policy Requirements[.]”)

²⁷¹ PJM and PPL are performing a full impact analysis, evaluating the technical, market efficiency, and reliability benefits, integration requirements (such as communication, system, operating protocols and governing documents), and a functional area impact assessment (including analyses of markets, operations, and planning and risk management

DLR sensors are scheduled for production deployment in 2022,²⁷² work remains to be done to ensure the forecasted benefits are recognized in real time system operations.

b. PJM Does Not Believe DLRs and APFC Devices Should Be Relied Upon as an Alternative to Transmission Build, Particularly with Respect to Addressing Identified Reliability Criteria Violations

DLRs and APFC devices, when selectively deployed, can support the efficient use of existing transmission infrastructure. Additionally, as described above, these technologies can provide some operational benefits, maximizing utilization of existing assets, but cannot address significant capacity enhancement needs (short and long-term) or long-range transmission needs under rapid growth or changing resource mix scenarios. DLRs and APFC devices they are not long-term solutions that can serve as blanket substitutes for the need for transmission expansion. It would not be accurate to view DLR or APFC devices as the “silver bullet” that obviate the need for long-term regional transmission planning, most especially reliability criteria-based transmission.

DLRs’ limitations in these situations are especially evident when the reliability need for a planning solution is independent of thermal line limits. Planning upgrades for reliability criteria are implemented to address reliability constraints at peak or light load for the planning horizon (one to fifteen years forward). Implementing DLR to mitigate this reliability scenario and associated reliability criteria violations would introduce additional risk to load serving reliability and generation deliverability assurance for loss of load expectancy assessments. This is due to

impacts). PJM is also continuing to assess necessary data requirements, associated data volume, rating methodologies, and reliability compliance associated with DLR implementation. PJM is further assessing the interplay between NERC Standards and DLR implementation, and the impact DLR might have on the standards for establishing, monitoring, and controlling system operating limits.

²⁷² <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220811/item-13---ppl-dlr-update.ashx>.

relying on forecasted wind and temperature conditions at some forward time interval far into the future in the hopes that the ambient conditions could enable the higher DLR.

APFC devices are also not an appropriate solution to address reliability needs. Wide incorporation of multiple APFC devices pose challenges to real-time operations and existing power flow analytical techniques. Increased use of these types of devices would alter how power flows on the grid, requiring analysis to become iterative following an initial contingency to determine if the “cascading” use of the devices is triggering a condition which may result in a new overload, in an iterative fashion as flows on other lines are altered.

In short, deployment of DLRs and APFC devices should not be seen as replacing capacity addition enhancements to address an identified reliability criteria violation. Although DLRs and APFC devices can be useful tools in managing and operating existing transmission capacity, PJM respectfully requests that the Commission recognize the limitations of these technologies as a solution to be relied upon in lieu of transmission build, particularly as a way to address identified reliability criteria violations in long-term transmission planning processes and ensure that it appropriately “scales” its statements as to the value of this technology as well as its inherent limitations.

PJM therefore requests that the Commission confirm that it does not intend to suggest that DLRs and APFC devices could be seen as a wholesale substitute for long-term transmission planning and investment to build new transmission or upgrading existing facilities. In addition, PJM respectfully requests that the Commission temper its statements in the Final Order so as to educate the public on not just the benefits but also the limitations of these technologies, so that overly broad Commission pronouncements do not further complicate already challenging siting processes.

C. Absent Future Agreement by All Affected States, PJM Believes that Existing *Ex Ante* Cost Allocation Methodologies Should Be Applied to Facilities Selected Pursuant to the Long-Term Regional Transmission Planning Process

The Commission proposes to require transmission providers to revise their tariffs to include either: (i) an *ex ante* cost allocation process that may apply to an individual facility selected as part of a Long-Term Regional Transmission Planning process; (ii) an *ex poste* cost allocation process pursuant to which one or more relevant state entities may voluntarily agree to a cost allocation method; or (iii) a combination of the two.²⁷³ The Commission further proposes to require transmission providers to seek the agreement of relevant state entities regarding the development of these methodologies.²⁷⁴ PJM discusses the Commission’s proposal below.

1. Background Regarding PJM’s Existing Cost Allocation Methodologies

a. PJM’s Existing Cost Allocation Methodologies Were Developed with State and Stakeholder Input. PJM Requests that the Commission Confirm that it Does Not Intend to Require Reconsideration of Existing Settled Cost Allocation Methodologies Absent Future State and Transmission Owner Agreement on Alternative Cost Allocations

PJM agrees that knowing how costs of transmission facilities will be allocated is “critical to the development of new transmission infrastructure.”²⁷⁵ Although the NOPR opens the door to discuss an option to allow states to develop alternative cost allocations, PJM underscores that it already has specific cost allocations for (i) reliability-based projects,²⁷⁶ (ii) market efficiency

²⁷³ NOPR at P 302.

²⁷⁴ *Id.*

²⁷⁵ *Id.* at P 297 (*citing* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557).

²⁷⁶ Tariff, Schedule 12, section (b).

projects;²⁷⁷ (iii) public policy projects addressing state-identified needs;²⁷⁸ and (iv) multi-driver projects.²⁷⁹ Each of those cost allocation methodologies were developed through close consultation and extensive work with the states in the PJM Region.

For example, PJM’s cost allocation method for reliability-based regional transmission facilities resulted from extensive settlement discussions before the Commission in Docket No. EL05-121.²⁸⁰ The states in the PJM Region were actively involved in those discussions and, in fact, many were listed as either settling parties or non-opposing parties to the settlement agreement.²⁸¹ By the same token, PJM’s cost allocation methodology for state public policy-driven transmission projects is embodied in its State Agreement Approach.²⁸² This methodology was developed jointly with the Organization of PJM States, Inc. (“OPSI”), and was supported by an OPSI Resolution dated November 12, 2012.²⁸³

²⁷⁷ *Id.*, section (b)(v).

²⁷⁸ *Id.*, section (b)(xii).

²⁷⁹ Operating Agreement, Schedule 6, section 1.5.10. Multi-driver project costs are allocated pursuant to the Tariff, Schedule 12, section (b)(xiv). The process was proposed to fit under the Commission-accepted Order No. 1000 RTEP process. *PJM Interconnection, L.L.C. and Baltimore Gas & Electric Co., et al.*, Joint Response to Deficiency Notice, Docket No. ER14-2864-000 and ER14-2867-000 (not consolidated) (Dec. 23, 2014) (“December 2014 Deficiency Response”).

²⁸⁰ See *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,233 (Dec. 18, 2014) (establishing hearing and settlement judge procedures regarding the cost allocation methodology for certain transmission facilities that operate at 500 kV and above in the PJM Region); see *PJM Interconnection, L.L.C.*, Order of Chief Judge Designating Settlement Judge and Scheduling Settlement Conference, Docket No. EL05-121-009 (Jan. 5, 2015); *PJM Interconnection, L.L.C.*, Status Report (May 31, 2016) (listing settlement conferences held on May 5, 2016, December 16, 2015, August 6, 2015, June 9, 2015, April 17, 2015, March 5, 2015, February 11, 2015 and January 14, 2015).

²⁸¹ See *PJM Interconnection, L.L.C.*, Offer of Settlement, Docket No. EL05-121-009 (June 15, 2016). The following state commission in the PJM Region actively participated in the settlement negotiations: (i) Settling Parties included Illinois Commerce Commission, Indiana Utility Regulatory Commission, Michigan Public Service Commission, Pennsylvania Public Utility Commission, Public Service Commission of West Virginia, and Public Utilities Commission of Ohio; and (ii) Non-Opposing Parties included Delaware Public Service Commission, New Jersey Board of Public Utilities, Public Service Commission of the District of Columbia and Virginia State Corporation Commission.

²⁸² See Operating Agreement, Schedule 6, section 1.5.9; see also PJM Tariff, Schedule 12, section (b)(xii).

²⁸³ OPSI Resolution # OPSI-2012-1 (Jan. 5, 2012) at <https://opsi.us/wp-content/uploads/2018/08/OPSI-2012-1.pdf>. See also, *PJM Interconnection, L.L.C.*, Motion to Intervene and Comments of the Organization of PJM States, Inc., Docket No. ER13-198-000, at 1 (Dec. 10, 2012) (“OPSI Compliance Filing Comments”). The SAA process was

PJM therefore urges the Commission to not simply throw in the air established cost allocation agreements that were the result of collaboration with states and other stakeholders, and have worked well in PJM. PJM requests that the Commission clarify in any Final Rule that although the states are free to work with transmission owners,²⁸⁴ PJM and stakeholders on any new cost allocation methods, the NOPR was not intending to force de novo reconsideration of existing settled cost allocation methods. This clarification is vitally important, as agreements on the existing cost allocations were only reached after years of discussion and litigation both before the Commission and the courts.²⁸⁵

b. PJM’s Existing Cost Allocation Methodologies Were Developed Consistent with Commission Precedent and the PJM CTOA. PJM Requests that the Commission Clarify the Interrelationship Between the NOPR Cost Allocation Proposals and Existing Precedent Regarding PJM Transmission Owners’ FPA Section 205 Filing Rights

PJM further asks the Commission to clarify the interrelationship of the proposals set forth in the NOPR with the PJM Region’s present allocation of rights to revise existing or propose new

supported by individual PJM states. For instance, the Delaware Public Service Commission stated that the approach represented an “important and some would argue, the most important) culmination of the process states will utilize to identify and evaluate, review and consider, and, ultimately, approve for payment those transmission projects satisfying transmission needs driven by public policy requirements.” *PJM Interconnection, L.L.C.*, Comments of the Delaware Public Service Commission, Docket No. ER13-198-000, at 4 (Dec. 10, 2012); The New Jersey Board of Public Utilities viewed the SAA as the “cornerstone of [PJM’s] Compliance Filing” that “correctly balances the desire to develop transmission assets to meet public policy goals with the need of states like New Jersey to ensure their elected officials retain ownership over associated costs.” *PJM Interconnection, L.L.C.*, Motion to Intervene and Comments of the New Jersey Board of Public Utilities, Docket No. ER13-198-000, at 2-4 (Dec. 12, 2012); The Public Utilities Commission of Ohio urged the Commission to approve the SAA process. *PJM Interconnection, L.L.C.*, Comments Submitted on Behalf of the Public Utilities Commission of Ohio, Docket No. ER13-198-000, at 7 (Dec. 10, 2012); The Illinois Commerce Commission found that the SAA process is a method by which projects that states determine are necessary to develop in order to achieve a state’s public policy requirements are included in PJM’s RTEP. *PJM Interconnection, L.L.C.*, Notice of Intervention and Comments of the Illinois Commerce Commission, Docket No. ER13-198-000, at 5 (Dec. 10, 2012).

²⁸⁴ See Section III.C.1.b, *infra*, discussing PJM transmission owners’ exclusive and unilateral section 205 filing rights set forth in Tariff, section 9.1 and Consolidated Transmission Owners’ Agreement (“CTOA”) §§ 7.1 and 7.3.

²⁸⁵ PJM acknowledges that there is still litigation initiated by Merchant Transmission Facilities regarding certain cost allocation details such as application of the *de minimis* rule and netting to solution-based DFAX; however, any Final Rule should not be a basis to overturn Commission-accepted cost allocation methodologies.

cost allocation methods, which is embodied in the *Atlantic City v. FERC* decision.²⁸⁶ Under the CTOA,²⁸⁷ PJM Tariff at section 9.1 and the settlement agreement between PJM and the PJM Transmission Owners that ended the *Atlantic City v. FERC* litigation,²⁸⁸ the PJM transmission owners have exclusive authority and responsibility to submit filings under FPA section 205 “in or relating to . . . the transmission rate design under the PJM Tariff.”²⁸⁹

Thus, even though PJM agrees that providing state regulators with a formal opportunity to work with the PJM transmission owners to develop a cost allocation method for facilities selected through Long-Term Regional Transmission Planning process will increase stakeholder and affected state authorities’ support for those facilities and that, in turn, the likelihood those facilities

²⁸⁶ See *Pennsylvania-New Jersey-Maryland Interconnection*, 105 FERC ¶ 61,294 (2003), *order on reh’g*, 108 FERC ¶ 61,032 (2004) (PJM) (approving Settlement Agreement). The provisions of the Settlement Agreement were memorialized in Tariff, section 9.1(a) which provides: “The Transmission Owners shall have the exclusive and unilateral rights to file pursuant to Section 205 of the [FPA] and the [Commission’s] rules and regulations thereunder for any changes in or relating to the establishment and recovery of the Transmission Owners’ transmission revenue requirements or the transmission rate design under the PJM Tariff, and such filing rights shall also encompass any provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by the Transmission Owners.” Tariff, section 9.1(d) further specifies that the PJM Transmission Owners’ unilateral filing rights include any changes to Tariff, Schedule 12, which sets forth the methodologies for allocating costs of transmission enhancements and expansions included in PJM’s RTEP). See *Atlantic City Elec. Co. v. F.E.R.C.*, 295 F.3d 1 (D.C. Cir. 2002), *order on remand*, *Pennsylvania–New Jersey–Maryland Interconnection*, 101 FERC ¶ 61,318 (2002), *subsequent appeal*, 329 F.3d 856 (D.C. Cir. 2003).

²⁸⁷ CTOA §§ 7.1.1, 7.1.3, 7.3.1, 7.3.2 & 7.3.4.

²⁸⁸ See *Pennsylvania-New Jersey-Maryland Interconnection*, 105 FERC ¶ 61,294 (2003), *order on reh’g*, 108 FERC ¶ 61,032 (2004) (PJM) (approving Settlement Agreement). The provisions of the Settlement Agreement were memorialized in Tariff, section 9.1(a) which provides: “The Transmission Owners shall have the exclusive and unilateral rights to file pursuant to Section 205 of the [FPA] and the [Commission’s] rules and regulations thereunder for any changes in or relating to the establishment and recovery of the Transmission Owners’ transmission revenue requirements or the transmission rate design under the PJM Tariff, and such filing rights shall also encompass any provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by the Transmission Owners.” Tariff, section 9.1(d) further specifies that the PJM Transmission Owners’ unilateral filing rights include any changes to Tariff, Schedule 12, which sets forth the methodologies for allocating costs of transmission enhancements and expansions included in PJM’s RTEP). See *Atlantic City Elec. Co. v. F.E.R.C.*, 295 F.3d 1 (D.C. Cir. 2002), *order on remand*, *Pennsylvania–New Jersey–Maryland Interconnection*, 101 FERC ¶ 61,318 (2002), *subsequent appeal*, 329 F.3d 856 (D.C. Cir. 2003).

²⁸⁹ See CTOA § 7.3.1. See also *PPL Elec. Utils. Corp.*, 177 FERC ¶ 61,123, at PP 34-37 (2021) (affirming the scope of the PJM Transmission Owners’ FPA section 205 filing rights under the Tariff and CTOA).

will be sited and ultimately developed,²⁹⁰ such opportunities must be harmonized with the transmission owners' filing rights set forth in the CTOA and Tariff provisions. The Commission should provide the requested clarification in its Final Rule that it is not intending to disturb the existing *Atlantic City* precedent and Settlement Agreement.

2. Absent Agreement Among All Affected States Regarding a Cost Allocation Methodology to Apply to Transmission Facilities Selected Through the Long-Term Regional Transmission Planning Process, Existing *Ex Ante* Cost Allocation Methodologies Should Apply

a. An *Ex Ante* LTRT Cost Allocation Method Should Be the Default Cost Allocation Methodology for Facilities Selected Through a Long-Term Regional Transmission Planning Process

The Commission has long recognized that an *ex ante* allocation methodology, as set forth in the Tariff and applied consistently (without re-litigation for each project approved), provides upfront certainty as to who will pay to build new infrastructure so that such needed transmission is in fact developed.²⁹¹ Regarding the allocation method itself, PJM's analysis under a Long-Term Regional Transmission Planning process will come from inputs related to public policy and load growth trends. Today, PJM incorporates load growth in its RTEP analysis and assigns the results to a reliability and/or market efficiency need. Absent a state's or states' election to use the State Agreement Approach process, there is no planning driver, other than the reliability or market efficiency planning drivers, by which PJM can incorporate future generation.²⁹²

²⁹⁰ NOPR at P 299.

²⁹¹ Opinion No. 494 at PP 65, 66 (finding that “[f]or a method to provide *ex ante* certainty, the key criteria, metrics and assumptions must be set forth in the tariff with sufficient specificity that they are not re-litigated each time a new project is approved by the RTO.”)

²⁹² In PJM's current five-year RTEP, or its analysis out through its 15-year planning horizon, PJM would incorporate new generation with an executed Interconnection Service Agreement; or, if necessary, generation at the Facility Study stage of the queue process may be included to meet high load expectations. *See* PJM, *Manual 14B: PJM Region Transmission Planning Process*, § 2.5 (rev. 51, Dec. 15, 2021). Of course, PJM has the ability to select a project that

Consequently, absent state agreement under the State Agreement approach, the need for new or expanded transmission facilities identified under a Long-Term Regional Transmission Planning process would still fall under the reliability or market efficiency studies performed today. And, because the studies used to identify the short- and long-term needs are the same, PJM does not believe that the cost allocation method for facilities under the Long-Term Regional Transmission Planning process must be different from the cost allocation methods used today for reliability, economic, public policy and multi-driver projects. Allowing PJM to use its existing *ex ante* cost allocation approaches will provide consistency and certainty to assigning cost responsibility for facilities selected through a Long-Term Regional Transmission Planning process. As a result, PJM proposes that transmission providers be permitted to use existing *ex ante* cost allocation methodologies as the default cost allocation methodology to apply to facilities selected through the Long-Term Regional Transmission Planning process (absent agreement by all affected states regarding an alternate methodology as discussed below).

Moreover, PJM seeks assurance from the Commission that any Final Rule will make clear that if a transmission provider proposes to use its current allocation methods for facilities under the Long-Term Regional Transmission Planning process, such a proposal could not be grounds for re-litigating cost allocation decisions for transmission facilities included in the RTEP prior to the effective date of any Final Rule in the docket.²⁹³

provides more capability to facilitate new anticipated generation if PJM is presented with two comparable solutions (similar in cost and performance) and one solution appears to be more accessible to future anticipated generation.

²⁹³ NOPR at P 314 (stating that cost allocation reforms would apply “only to new Long-Term Regional Transmission Facilities and, therefore, [the] proposed reforms would not provide grounds for re-litigation of cost allocation decisions for transmission facilities that are selected in the regional transmission plan for purposes of cost allocation prior to the effective date of any Final Rule in this proceeding, nor would they apply to the cost allocation methods associated with regional transmission facilities that address shorter-term transmission needs driven by reliability and/or economic considerations.”).

b. PJM Proposes to Continue Using its Existing State Agreement Approach Process Consistent with Any Final Rule

PJM does not propose to modify its existing State Agreement Approach process to apply to the Long-Term Regional Transmission Planning process. Rather, PJM anticipates continuing to use its State Agreement Approach process for those instances where a state(s) approaches PJM to request to voluntarily sponsor a project that its customers will fund. Nonetheless, based on PJM's experience, if the Commission ultimately determines to allow a State Agreement Approach process for facilities selected through the Long-Term Regional Transmission Planning process, PJM recommends that the Commission allow each region flexibility in defining the process and associated cost allocation method.

The State Agreement Approach, by definition, includes the consultation with states and stakeholders that the proposed Long-Term Transmission Planning Process also suggests. As exemplified in the record in Docket No. ER22-902,²⁹⁴ there is an iterative consultation process under the State Agreement Approach where needs are identified, PJM works to identify options for state consideration and ultimately the state makes a determination whether or not it wishes to proceed with the project.

In short, there is no conflict between the current State Agreement Approach process and the development of State Agreement Approach projects in consultation with states and stakeholders called for in the proposed Long-Term Regional Transmission Planning process. For these reasons, the Commission should not feel the need to force PJM and OPSI to “re-justify” the State Agreement Approach through the compliance process as this would just increase uncertainty

²⁹⁴ See n.212, *supra*.

and disturb existing efforts underway in PJM and the OPSI states to use the State Agreement Approach process to develop offshore wind resources both off the coast of New Jersey and more broadly offshore with respect to a number of PJM states. This is simply not the time to deflect resources away from moving forward on this important State Agreement Approach work simply to “re-justify” processes through elongated compliance litigation, that already accommodate the Long-Term Regional Transmission Planning processes as demonstrated in the record in Docket No. ER22-902.

c. PJM Supports Allowing an Opportunity for States to Determine Whether they Can Agree on an Alternate *Ex Post* Cost Allocation Method

The Commission proposes to require transmission providers to revise their tariff to add a time period for states to negotiate an alternate cost allocation method that would apply to a facility selected through a Long-Term Regional Transmission Planning process.²⁹⁵ PJM supports a process pursuant by which states would have the opportunity to negotiate an alternate *ex post* cost allocation methodology to apply to such a project. PJM believes it is critical that the Commission provide clear direction as to the circumstances under which it would be appropriate for a state or states to seek to negotiate and use an alternate to the *ex post* method.

For example, in addition to a defined timeframe in which the states must reach agreement on an alternate method, PJM proposes that states seeking to use a state-negotiated alternate allocation method should be required to explain why the *ex ante* approach is not appropriate for the facility or facilities identified pursuant to the Long-Term Regional Transmission Planning process.²⁹⁶ Given the significance of setting aside the *ex ante* allocation method for a state-

²⁹⁵ NOPR at PP 279, 319.

²⁹⁶ *Id.* at P 323.

negotiated alternative, PJM agrees with the proposal that any alternate cost allocation method must be unanimously endorsed by the states impacted by the alternate cost allocation method.²⁹⁷

PJM believes that absent unanimous agreement by all states potentially impacted by an alternate cost allocation methodology, the existing *ex ante* allocation methodology must apply to the facilities selected through the Long-Term Regional Transmission Planning process. Additionally, if the transmission provider determines not to file the alternate method or the Commission does not approve the alternate method, the applicable tariffed *ex ante* cost allocation method will be used to assign cost responsibility for the facility.²⁹⁸

3. PJM Proposes the Following Revisions Related to Cost Allocation for Incorporation in the Final Rule

In order to effectuate PJM's recommendations related to cost allocation set forth above, PJM recommends that the Commission modify Attachment K of the *pro forma* OATT as follows:

In the paragraph which begins "*The Transmission Providers in each transmission planning region shall include...*", after the sentence: "*The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable cost allocation method*" add:

*Transmission Providers shall be able to continue to use cost allocation methods developed through planning processes with shorter term planning horizons (a) for projects developed pursuant to such processes and (b) as a default cost allocation should states and stakeholders not be able to reach agreement on alternative cost allocation methods for projects chosen through the long-term regional transmission planning process.*²⁹⁹

²⁹⁷ *Id.* at P 319.

²⁹⁸ *Id.* at P 320.

²⁹⁹ See Appendix A at 11.

D. PJM Believes the CWIP Incentive Proposal as Written May Have Unintended Consequences

The Commission proposes that transmission owners would not be permitted to take advantage of the construction-work-in-progress (“CWIP”) incentive for facilities developed pursuant to the Long-Term Regional Transmission Planning process.³⁰⁰ Instead, the Commission proposes replacing the CWIP incentive with an Allowance for Funds Used During Construction,³⁰¹ meaning that transmission owners can recover costs — including financing costs — once their transmission facility is put into service.

PJM cautions the Commission that removing this incentive for facilities developed pursuant to the Long-Term Regional Transmission Planning process might complicate the construction of such facilities, *i.e.*, if project right-sizing is based on both near- and long-term analysis, Long-Term Regional Transmission Planning project selection is based on overlapping needs from other considerations such as end of life facilities, etc.

While PJM shares the Commission’s concern that long-term planning involves more uncertainty and risk around the planning of Long-Term Regional Transmission Planning facilities and, therefore, a CWIP incentive for Long-Term Regional Transmission Planning facilities might shift too much risk to consumer, PJM finds that trying to manage these concerns by manipulating the timing of eligibility for transmission incentives may not be the right approach.

³⁰⁰ NOPR at P 333.

³⁰¹ *Id.*

E. PJM Supports the Concept of “Right-Sizing” Replacement Transmission Facilities as a Way to Help Address Needs Resulting from the Changing Resource Mix and Demand

In exploring other areas of regional transmission planning that could benefit from reforms through the proposed Long-Term Regional Transmission Planning process,³⁰² the Commission focuses on the nation’s aging transmission infrastructure and notes that: (i) many incumbent transmission owners are replacing aging transmission facilities without evaluating whether those replacements could be “right-sized”³⁰³ to more efficiently or cost effectively address regional transmission needs; and, as a result, (ii) transmission providers may not be privy to information necessary to identify whether there are benefits to be gained by either deferring or eliminating the need for in-kind replacements.³⁰⁴ In order to improve the coordination between regional and local transmission planning with the aim of identifying potential opportunities to “right-size” replacement transmission facilities,³⁰⁵ the Commission proposes to require:

- inclusion of an iterative planning process through the addition of tariff revisions that provide for additional transparency into transmission owners’ local transmission planning processes in order to better facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than the proposed local transmission facilities,³⁰⁶ and
- as part of the Long-Term Regional Transmission Planning process planning cycle, that transmission providers evaluate whether transmission facilities operating at or above 230 kV that a transmission owner anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right-sized” to more efficiently or cost effectively address long-term regional transmission needs.³⁰⁷

³⁰² *Id.* at P 3.

³⁰³ *Id.* at P 403 (“right-sizing” is defined in the NOPR to mean the process of modifying a [transmission owner’s] in-kind replacement of an existing transmission facility to increase that facility’s transfer capability,” *e.g.*, increasing the transmission facility’s voltage level, adding circuits to towers or incorporating advanced technologies.).

³⁰⁴ *Id.* at P 399.

³⁰⁵ *Id.*

³⁰⁶ *Id.* at P 400.

³⁰⁷ *Id.* at PP 403-405 (such proposed reform would require (i) the transmission owner to submit a list of its existing transmission facilities operating at or above 230 kV that it estimates may need to be replaced with a new in-kind

PJM’s Tariff already provides for a transparent, iterative planning process that affords stakeholders meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process.³⁰⁸ PJM therefore limits these comments to addressing whether transmission providers should be required to evaluate whether transmission facilities operating at or above 230 kV can be “right-sized” to address regional transmission needs identified in the Long-Term Regional Transmission Planning process.

Determining “right-sizing” candidates is not an exact science, and would need to be based on facilities’ age and typical equipment life span,³⁰⁹ as well as the short- and long-term needs. The number of transmission facilities – at all voltage levels – that are approaching their end of useful life across the PJM region continues to grow. As existing infrastructure continues to age, right-sizing can provide an important opportunity to address needs resulting from the changing resource mix and demand. Right-sizing facilities through a Long-Term Regional Transmission Planning process has the potential to allow the transmission owner to meet its reliability obligations, and can give the transmission provider the ability to identify more efficient or cost-effective solutions

facility over the next 10 years; and (ii) transmission provider to review and evaluate whether any of the facilities on the list can be “right-sized” to address a transmission need identified in Long-Term Regional Transmission Planning)

³⁰⁸ PJM Tariff’s local planning processes providing for review of Attachment M-3 Projects that include, among other things: (i) review of Attachment M-3 Projects that allows the Subregional RTEP Committees to have a meaningful opportunity to participate and provide feedback, including written comments for Attachment M-3 Projects; (ii) review transmission owner’s criteria, assumptions and models through a minimum of one Subregional RTEP Committee meeting; (iii) schedule a minimum of one Subregional RTEP Committee meeting per planning cycle to review identified criteria violations and resulting system needs; (iv) schedule a minimum of one Subregional RTEP Committee per planning cycle to review potential solutions for identified criteria violations, as well as any alternative solutions identified by transmission owners or stakeholders; and (v) each transmission owner will finalize for submittal to the transmission provider Attachment M-3 Projects for inclusion in the Local Plan. Tariff, Attachment M-3, section (c).

³⁰⁹ Whether or not age of facility information may be publicly disclosed will be determined based on whether such information must be maintained as confidential under the relevant Governing Documents.

based on needs identified through the Long-Term Regional Transmission Planning process.³¹⁰ It could also help transmission providers avoid duplicative or inefficient transmission development.³¹¹

Additionally, while PJM supports application of right-sizing for transmission facilities operating at or above 230 kV,³¹² PJM also encourages the Commission to explore the potential benefits of extending application of “right sizing” to include transmission facilities at 100 kV as part of Long-Term Regional Transmission Planning process, provided it does not delay the planning of short-term reliability needs. Allowing the transmission providers the discretion to evaluate whether lower voltage facilities may benefit from right-sizing could help further the Commission’s goal of achieving greater efficiencies through the Long-Term Regional Transmission Planning process.

Accordingly, for the reasons set forth above, PJM supports the concept of “right-sizing” replacement transmission facilities as a way to help address needs resulting from the changing resource mix and demand. That said, PJM observes and is not proposing to change the Commission’s proposal that the transmission owner that identifies the transmission facilities that it anticipates replacing in-kind during the next 10 years would not be bound by the transmission provider’s potential right-sizing solution “in spite of the potential efficiencies of right-sizing identified in the regional transmission planning process.”³¹³

³¹⁰ NOPR at P 406.

³¹¹ *Id.* at P 408.

³¹² *Id.* at P 403 (proposing to require that, as part of the Long-Term Regional Transmission planning cycle, transmission providers evaluate whether transmission facilities operating at or above 230 kV can be right-sized to more efficiently or cost effectively address regional transmission needs identified through an Long-Term Regional Transmission planning process.).

³¹³ *Id.* at P 408.

F. PJM Believes that Proposed Reforms Specific to Interregional Coordination Should Not Be Limited to Sharing Information or Identifying Interregional Transmission Facilities to Address Needs Identified Specific to the Long-Term Regional Transmission Planning Processes

In its Initial ANOPR Comments, PJM stated that, in its opinion, “the answer to enhancing interregional coordination lies in creating the analytical framework and transmission planning driver focused on improvements in interregional transfer capability to support [Enhanced Reliability] across the seams.”³¹⁴ The NOPR’s proposed reforms for interregional transmission coordination are narrowly limited to requiring neighboring regions to revise their existing interregional coordination procedures (and regional planning processes as needed) to provide for: (i) the sharing of information regarding transmission needs identified in the Long-Term Regional Transmission Planning, as well as the potential regional facilities to meet those Long-Term Regional Transmission Planning needs; and (ii) the identification and joint evaluation of interregional transmission facilities that may be the more efficient or cost effective solution to address transmission needs identified in the Long-Term Regional Transmission Planning process.³¹⁵

While PJM agrees that the proposed reforms are necessary to appropriately provide for updating interregional coordination agreements to require the sharing of information identified through a Long-Term Regional Transmission Planning process, as well as identify and consider interregional transmission facilities that may more efficiently or cost effectively address transmission needs identified under the Long-Term Regional Transmission Planning process, more is needed to prepare for the future trends and needs associated with the evolving resource

³¹⁴ PJM Initial ANOPR Comments at 69.

³¹⁵ NOPR at P 427.

mix and increasing frequency of extreme weather events, both of which will likely place greater reliance on neighbors in the future. To that point, PJM believes the Commission could and should act more decisively now to prepare for those anticipated needs by driving the development of a robust standardized minimum interregional transfer capability methodology that would inform future interregional transmission coordination to help ensure that there is adequate transfer capability between regions, so as to enhance both reliability and resilience as the nation faces more extreme weather and other related challenges.

PJM recommends that the Commission move forward with a transmission planning driver that would recognize the value of interregional transfer capability, including development of a standard methodology (and planning driver to support transmission expansions to meet that methodology) in an effort to evaluate an appropriate level of import/export capability that supports a larger more reliable and resilient grid.³¹⁶ Accordingly, in Section III.A.2.b, above, PJM proposes the Commission add a ninth Factor to the list of factors set forth in NOPR P 104 to be considered in Long-Term Scenario planning, as follows: “(9) the application of future interregional transfer capability methodologies to be determined by a subsequent Commission Order after consultation with the Department of Energy national laboratories and industry stakeholders.”

To further assist the Commission in the development of a robust standardized minimum interregional transfer capability methodology, PJM believes its recommendation of how to proceed that was included in its Initial ANOPR Comments bears repeating here:

The Commission should embrace the development of a decision analysis and transmission planning driver that would recognize the value of interregional transfer capability to ensure a more reliable and resilient grid in the face of extreme weather and other challenges. To provide the analytical framework to guide this effort, the Commission could work with the industry and stakeholders to explore

³¹⁶ See Section III.F, *infra*.

the development of a standardized minimum interregional transfer capability methodology by Balancing Authority (*i.e.*, X% of load). The transfer methodology evaluation should consider resilience, in the form of extreme event planning, which may serve as input into the development of the transfer methodology. Depending on the results, a national standard or recommended planning driver for transfer capability to enable delivery of power driven by multiple drivers (reliability, market efficiency, public policy and resilience) could yield criteria for which interregional planning can be pursued.³¹⁷

Additionally, PJM also urges the Commission to provide guidance on the issue of cost allocation for upgrades designed to increase transfer capability by defining such determinations as a cognizable “benefit” for purposes of applying the legal standard that costs must be allocated “roughly commensurate with” benefits.³¹⁸ These benefits might be tied to analysis that could include the examination of the need to maintain reserve margins under various regional extreme conditions, and/or tied to projected or historical emergency transfer requirements. All regions could then be allocated their fair share based on consistently-applied methodology and decision analysis defined by the Commission that is tied to enhancing the reliability and resilience between regions.

Finally, leaving this important task to the regions to negotiate will simply not work. Without a common methodology there could be very different results between regions, yet we are all part of one large Interconnection. More importantly, in the past, negotiations between neighbors on interregional issues have bogged down as each region looks at the interregional issues strictly in the context of their respective regional needs and processes. Conversely, a common methodology would ensure a common reliability-based focus that takes into account the larger impacts across the entire Interconnection.

³¹⁷ ANOPR at P 74.

³¹⁸ *Id.* at PP 72, 74 and 75.

G. PJM Believes the Commission Underestimates the Cost and Time Needed to Implement the Proposals Set forth in the NOPR; PJM Requests a Reasonable Compliance Period

1. The Commission Underestimates the Burdens Associated with Implementation of the NOPR's Proposals

The Commission explains that the reforms proposed in the NOPR will require revisions to the Commission's *pro forma* OATT and *pro forma* Large Generator Interconnection Procedures ("LGIP") "to correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements...."³¹⁹ As part of the NOPR, the Commission provides a chart listing the estimated burden hours³²⁰ and total estimated costs associated with several revisions proposed in the NOPR, both on an individual respondent basis³²¹ and on an industry-wide basis.³²² The Commission estimates hours and costs on an annual basis by initial compliance year and subsequent compliance year. PJM does not comment on the Commission's industry-wide assumptions here, but for the reasons demonstrated below, PJM believes the Commission underestimates the time, effort, and financial resources that individual RTOs like PJM will have to expend in order to comply with any Final Rule in this docket.

Briefly, the Commission estimates the "maximum"³²³ burden on individual respondents associated with the various proposals set forth in the NOPR as follows:

- Participating in Long-Term Regional Planning (which it states includes: (i) developing Long-Term Scenarios; (ii) evaluating the benefits of regional transmission facilities; and (iii) establishing criteria in consultation with states to

³¹⁹ NOPR at P 435.

³²⁰ The Commission defines "burden" as "the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency." NOPR at P 449, n. 682.

³²¹ See P 449, Column D.

³²² See P 449, Column E.

³²³ The Commission states that its estimate of burdens is "conservative," and states that while the burdens for some respondents may be lower than estimated, "other respondents may incur the maximum benefits." NOPR at P 450.

select transmission facilities in the regional transmission plan for purposes of cost allocation)

- Year 1: 150 hours; \$11,275
- Subsequent Years: 50 hours/year; \$3,758/year
- Revising the regional transmission planning process to enhance transparency of local transmission planning and identifying potential opportunities to “right-size” replacement facilities
 - Year 1: 20 hours; \$1,208
 - Subsequent Years: 50 hours/year; \$3,758/year
- Seeking agreement from states to establish a cost allocation methodology
 - Year 1: 150 hours; \$11,275
 - Subsequent Years: 50 hours/year; \$3,758/year
- Considering in regional transmission planning processes regional transmission facilities that address certain interconnection-related needs
 - Year 1: 50 hours/year; \$3,758/year
 - Subsequent Years: 0 hours/year; \$0/year
- Revising interregional transmission coordination procedure to reflect Long-Term Regional Transmission Planning
 - Year 1: 50 hours; \$3,758/year
 - Subsequent Years: 25 hours/year; \$1,715/year
- Revising the LGIP to indicate the consideration in the regional transmission planning processes of regional transmission facilities that address certain interconnection-related needs
 - Year 1: 30 hours; \$2,058
 - Subsequent Years: 0 hours/year; \$0/year

That is, the Commission estimates that individual respondents will expend 450 hours / \$32,332 implementing the NOPR proposals in Year 1, and 175 hours / \$12,989 in subsequent years.

Putting aside the fact that the estimates above do not even account for all of the proposals set forth in the NOPR, the Commission’s estimation of the time, effort, and financial resources that RTOs will need to spend to implement the elements of Long-Term Regional Transmission Planning provided for in the NOPR is simply unrealistic.

PJM will have to develop an entirely new planning process to accommodate the NOPR’s proposals. Although PJM and its stakeholders have already given a considerable amount of

thought about how to implement long-term, scenario-based planning,³²⁴ the Commission is proposing to require PJM to work with its stakeholders and the 14 jurisdictions within the PJM Region to, among other things: (i) develop multiple Long-Term Scenarios that reasonably capture probable future outcomes on a proposed 20-year forward basis; (ii) reassess those Long-Term Scenarios every three years; (iii) consider in those Long-Term Scenarios at least seven categories of Factors that include, among other things, federal, state, and local laws, regulations and policies that bear upon the resource mix, market trends in technology and fuel costs, electrification, resource retirements, generation interconnection, and nonbinding clean energy or emissions goals of governments and corporations; (iv) consider whether PJM can identify certain geographic areas that may be ripe for renewable development; and (v) identify and quantify benefits associated with transmission facilities that address needs driven by changes in the resource mix and electricity demand.

Each of these elements of the new Long-Term Regional Transmission Planning process will be resource-intensive. In fact, PJM anticipates that it will, at a minimum, have to create a new department within its Planning Group whose principle function will be to develop the Long-Term Scenario planning processes proposed in the NOPR, as well as undertake related planning activities. PJM has received approval to create the new department to support the development and implementation of the various studies and processes contemplated by the NOPR, with an initial staff of seven, for an estimated cost to PJM of approximately \$2.1 million/year.³²⁵ PJM anticipates that staffing may need to be expanded based on conversations with other ISO/RTOs to include a

³²⁴ See Appendix C, Master Plan White Paper.

³²⁵ This estimate is based on anticipated employee wages and benefits, plus typical department costs such as (contracting/consulting) dollars.

total of an additional 14 full-time employees, which would include Transmission Planning, State Policy Solutions, Member Services and Legal support staff.

PJM does not provide the information above to complain about having to comply with the NOPR proposals. To the contrary, as stated above, PJM generally supports the Commission's proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by changes in the resource mix and demand. However, PJM provides this information so the Commission has a better understanding of the time and costs that will likely be associated with implementing a Final Rule in this proceeding.

2. PJM Requests that the Commission Allow for a Reasonable Compliance Period

The Commission proposes an extended compliance period, pursuant to which each transmission provider must submit a compliance filing within eight months of the effective date of any Final Rule in this proceeding.³²⁶ PJM believes the eight-month compliance period is reasonable for most aspects of the NOPR should it become a Final Rule. However, PJM believes that the Commission must allow sufficient time for transmission providers to work with stakeholders and states to implement the Long-Term Regional Transmission Planning process. To that end, the Commission must allow for a reasonable amount of time for transmission planners to develop the tools and hire the employees they will need to implement the Final Rule.

IV. DOCUMENTS ENCLOSED WITH THIS FILING

PJM includes the following appendices:

- Appendix A: PJM's Proposed Revisions to Attachment K of the Commission's *Pro Forma* OATT;
- Appendix B: Executive Summary from PJM's 2018 Resilience Comments in

³²⁶ NOPR at P 430.

Docket No. AD17-7-000; and

- Appendix C: PJM Interconnection, Enhanced 15-Year Long-Term (Master Plan) White Paper (May 10, 2022).

V. CONCLUSION

PJM respectfully that the Commission consider: (i) the Comments set forth above, and (ii) PJM's proposed revisions to Attachment K of the *pro forma* OATT, set forth in Appendix A hereto.

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On behalf of PJM Interconnection, L.L.C.

Dated: August 17, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties on the official Service List compiled by the Secretary in these proceedings.

Dated at Audubon, Pennsylvania this 17th day of August, 2022.

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APPENDIX A

Appendix A:

Proposed Revisions to *Pro Forma* Open Access Transmission Tariff Attachment K

Note: PJM's proposed deletions are in **STRIKEOUT** and proposed additions are **UNDERLINED**. PJM has consolidated all proposed revisions included in its NOPR Comments in this Attachment K Appendix. Footnotes are cross-references to the Comments for explanatory purposes only.

ATTACHMENT K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open, and transparent *local transmission* planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open, and transparent *local transmission* planning process shall be provided as an attachment to the Transmission Provider's Tariff. The Transmission Provider's *local transmission* planning process shall satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new *transmission* projects. The *local transmission* planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The *local transmission* planning process also shall provide a mechanism for the recovery and allocation of *transmission* planning

costs consistent with Order No. 890. The description of the Transmission Provider's *local transmission* planning process must include sufficient detail to enable Transmission Customers to understand:

- (i) The process for consulting with customers;
- (ii) The notice procedures and anticipated frequency of meetings;
- (iii) The methodology, criteria, and processes used to develop a transmission plan;
- (iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;
- (v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;
- (vi) The dispute resolution process;
- (vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;
- (viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and
- (ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning

process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. For planning based on a time horizon greater than five years, the regional transmission planning process shall include a transmission planning driver that ensures that the transmission system is able to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such events. Criteria to be considered in the development and application of the aforementioned transmission planning driver include, but are not limited to, consideration of storm hardening of facilities and responsiveness plans, restoration planning for loss of critical infrastructure, planning to proactively prevent introduction of new CIP-014 facilities, and to “de-list” already identified CIP-014 facilities as well as gas/electric planning coordination to reduce vulnerabilities shared by both sectors.^[1]

The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000 and Order No. [final rule]. The regional transmission planning process shall be described in an attachment to the Transmission Provider’s Tariff.

¹ See PJM Comments, Section II.A.6.

The Transmission Provider’s regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of “*transmission* planning costs” consistent with Order No. 890 and *Order No. 1000*.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider’s Tariff.

As part of the regional transmission planning process, in addition to short-term reliability and economic planning processes promulgated pursuant to Order Nos. 890 and 1000,^[2] the Transmission Providers in each transmission planning region will conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking basis to identify transmission needs

² See PJM Comments, Section III.B.3.c.

driven by changes in the resource mix and demand, evaluate transmission facilities to meet such needs, and identify and evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission facilities to meet such needs. As part of this Long-Term Regional Transmission Planning process, the Transmission Providers in each transmission planning region will: (1) identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. [final rule]; (2) evaluate the broader set of benefits and beneficiaries of regional transmission facilities planned to meet transmission needs driven by changes in the resource mix and demand over a time horizon that covers, at a minimum, 20 15 years starting from the estimated in-service date of the transmission facilities; and (3) establish transparent and not unduly discriminatory criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address transmission needs driven by changes in the resource mix and demand in collaboration consultation with states and other stakeholders.^[3]

When developing Long-Term Scenarios, the Transmission Providers in each transmission planning region must: (1) use a transmission planning horizon no less than 20 15 years into the future^[4]; (2) reassess and revise Long-Term Scenarios including to reassess whether the data inputs and factors incorporated in their previously developed

³ See PJM Comments, Sections III.A.2.a; III.A.2.b(3); III.B.2.

⁴ See PJM Comments, Section III.A.2.a.

Long-Term Scenarios need to be updated and then revise their Long-Term Scenarios as needed to reflect updated data inputs and factors at least every three years, and complete the development of Long-Term Scenarios within three years, before the next three-year assessment commences; (3) incorporate, at a minimum, the ~~seven~~ nine categories of factors identified in Order No. [final rule] that may drive transmission needs driven by changes in the resource mix and demand;^[5] (4) develop a plausible and diverse set of at least four Long-Term Scenarios; (5) use “best available data” (as defined in Order No. [final rule]) in developing Long-Term Scenarios; and (6) consider whether to identify geographic zones with the potential for development of large amounts of new generation. The process through which the Transmission Providers develop Long-Term Scenarios also must comply with the following six transmission planning principles established in Order No. 890: coordination; openness; transparency; information exchange; comparability; and dispute resolution.

The Transmission Providers in each transmission planning region must identify the benefits they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The following set of Long-Term Regional Transmission Benefits may be useful for Transmission Providers in each transmission planning region in evaluating transmission facilities for selection in the regional transmission plan for

⁵ See PJM Comments, Section II.A.6.

purposes of cost allocation as the more efficient or cost-effective solutions to meet transmission needs driven by changes in the resource mix and demand: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; ~~and~~ (12) increased market liquidity; and (13) enhanced reliability.^[6]

Table 1: Long-Term Regional Transmission Benefits

Benefit	Description
<i>Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement</i>	<i>Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities</i>
<i>Reduced loss of load probability [OR next benefit]</i>	<i>Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load</i>
<i>Reduced planning reserve margin [OR prior benefit]</i>	<i>While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning</i>

⁶ See PJM Comments, Section II.A.6. Note, for the reasons described in its comments, PJM proposes to consolidate the 13 benefits detailed above into five (5) benefits for the PJM Region and a core subset of benefits to apply nationwide. See Comments at III.B.2.

<i>Production cost savings</i>	<i>reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings</i>
<i>Reduced transmission energy losses</i>	<i>Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand</i>
<i>Reduced congestion due to transmission outages</i>	<i>Reduced production costs during transmission outages that significantly increase transmission congestion</i>
<i>Mitigation of extreme events and system contingencies</i>	<i>Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system</i>
<i>Mitigation of weather and load uncertainty</i>	<i>Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns</i>
<i>Capacity cost benefits from reduced peak energy losses</i>	<i>Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses</i>
<i>Deferred generation capacity investments</i>	<i>Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas</i>
<i>Access to lower-cost generation</i>	<i>Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources,</i>

Increased competition

locations with high-quality renewable energy resources)

Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power

Increased market liquidity

Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for long-term transmission planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion

Enhanced Reliability

Ability of the grid to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.^[7]

As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region must include (1) transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand; and (2) a process to coordinate with relevant state entities in developing such criteria.

⁷ See PJM Comments, Section II.A.6. Note, for the reasons described in its comments, PJM proposes to consolidate the 13 benefits detailed above into five (5) benefits for the PJM Region and a core subset of benefits to apply nationwide. See Comments at III.B.2.

If the Transmission Providers include a portfolio approach in selecting transmission facilities in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand, then the Transmission Providers must include provisions describing whether the selection criteria would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in the resource mix and demand or would be used only in certain specified instances.

Transmission Providers in each transmission planning region shall include in their respective Tariffs the following statement: The regional planning process set forth in this Tariff shall include a transparent long-term scenario-driven process which shall, at a minimum, include long-term 15-year year forward assessments of transmission needs that (a) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the forecasted resource mix and demand; (b) consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs. Development of long term planning scenarios and their application to existing planning processes shall be developed after extensive consultation with stakeholders and states in the transmission planning region. The details of the long-term scenario development process shall be developed by the transmission provider in consultation with stakeholders and states and included in the Manuals. In addition, for a period of five years after adoption of (the Final Rule), the Transmission Provider shall provide the Commission with progress reports through informational filings detailing its work on developing a long term transmission planning

process consistent with Order No. xxx (Final Rule Order) and its adoption of manual provisions detailing such long term planning process.^[8]

The Transmission Providers in each transmission planning region shall include in their tariffs either (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof. A Long-Term Regional Transmission Cost Allocation Method is an ex ante regional cost allocation method that applies to a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand (Long-Term Regional Transmission Facility). The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable cost allocation method. Transmission Providers shall be able to continue to use cost allocation methods developed through planning processes with shorter term planning horizons (a) for projects developed pursuant to such processes and (b) as a default cost allocation should states and stakeholders not be able to reach agreement on alternative cost allocation methods for projects chosen through the long-term regional transmission planning process.^[9] A State Agreement Process is an ex post cost allocation process, which may apply to an

⁸ See PJM Comments, Section II.B.2.

⁹ See PJM Comments, Section III.C.3.

individual Long-Term Regional Transmission Facility or a portfolio of such Facilities grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected in the regional transmission plan for purposes of cost allocation, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement can be reached). If the Commission subsequently approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method. The Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities must comply with the existing six Order No. 1000 regional cost allocation principles.

Transmission Providers in each transmission planning region must seek the agreement of relevant state entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process.

The regional transmission planning processes must give a state or states a period of time to negotiate a cost allocation method for a transmission facility that is selected in the Long Term Regional Transmission Plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand that is different than the regional cost allocation method (alternate cost allocation method related to transmission needs driven by changes in the resource mix and demand).

The Transmission Providers in each transmission planning region shall consider

in regional transmission planning and cost allocation processes whether selecting transmission facilities in the regional transmission plan for purposes of cost allocation that incorporate dynamic line ratings, as defined in 18 CFR § 35.28(b)(14), or advanced power flow control devices would be more efficient or cost-effective than regional transmission facilities that do not incorporate these technologies. Specifically, such consideration must include both: (1) first, whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) second, when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, the Transmission Providers in each transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective.

This requirement applies in all of the Transmission Provider's regional transmission planning processes, including the regional transmission planning processes for near-term regional transmission needs and Long-Term Regional Transmission Planning required in Order No. [final rule]. The costs of transmission facilities that incorporate dynamic line ratings or advanced power flow control devices that are selected in the regional transmission plan for purposes of cost allocation will be allocated using the applicable regional cost allocation method. The Transmission Provider's evaluation process must culminate in a determination that is sufficiently

detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation. This process must include the consideration of dynamic line ratings and advanced power flow control devices and why they were not incorporated into selected regional transmission facilities.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

- (i) The process for enrollment in the regional transmission planning process;
- (ii) The process for consulting with customers;
- (iii) The notice procedures and anticipated frequency of meetings;
- (iv) The methodology, criteria, and processes used to develop a transmission plan;
- (v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;
- (vi) The obligations of and methods for transmission customers to submit data;
- (vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the *regional* transmission planning process and seek regional cost allocation;
- (viii) The process for submission of data by merchant transmission developers that wish to participate in the *regional* transmission planning process;

- (ix) The dispute resolution process;
- (x) The study procedures for economic upgrades to address congestion or the integration of new resources; *and*

[The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and]
- (xi) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process

The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's planning models:

- (1) A stakeholder meeting to review the criteria, assumptions, and models related to each Transmission Provider's local transmission planning (Assumptions Meeting);*
- (2) No fewer than 25 calendar days after the Assumptions Meeting, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting); and*

(3) No fewer than 25 calendar days after the Needs Meeting, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting).

Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above 230 kV that an individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right-sized” to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. “Right-sizing” means the process of modifying a Transmission Provider’s in-kind replacement of an existing transmission facility to increase that facility’s transfer capability. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. [final rule].

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans (*including information regarding the respective transmission needs identified in Long-Term Regional Transmission Planning and potential transmission facilities to meet those needs*) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

- (2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions, *including those that may be more efficient or cost-effective transmission solutions to transmission needs identified through Long-Term Regional Transmission Planning*;
- (3) An agreement to exchange, at least annually, planning data and information; and
- (4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

APPENDIX B

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Grid Resilience in Regional Transmission
Organizations and Independent System
Operators**

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Docket No. AD18-7-000

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

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March 9, 2018

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 management⁵ 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 include 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.

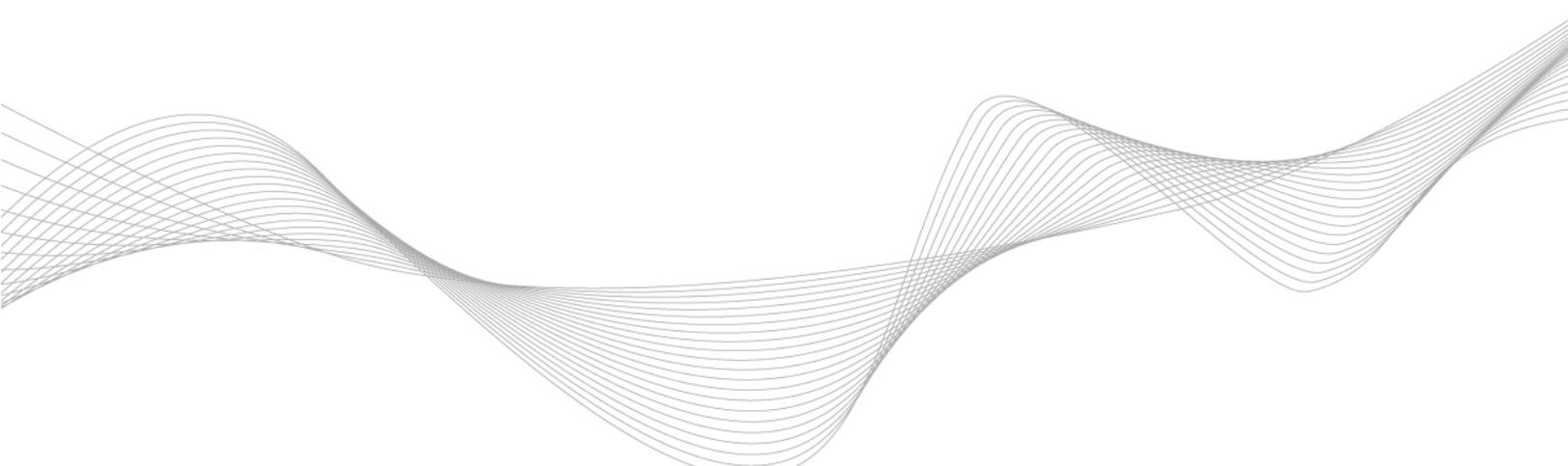
¹⁴ *Id.* at P 27.

APPENDIX C



Enhanced 15-Year Long-Term Planning (Master Plan) White Paper

PJM Interconnection
Date: May 10, 2022
Final



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I. Purpose

PJM has developed this white paper to outline the details of how best to work with states and other stakeholders to identify, from among an array of future scenarios, those which transmission planners could utilize to justify moving forward with directives to build new transmission.

The goal of the exercise is to develop a robust and transparent transmission planning process capable of proactively meeting customer needs and policy goals. Many commenters in the FERC Advance Notice of Proposed Rulemaking (ANOPR) docket have urged longer-range scenario-based planning. This paper is designed to take the discussion to the next level by addressing the question of how transmission planners, working with states and other stakeholders, can narrow down a vast number of future scenarios to determine those that should be deemed actionable for purposes of integrating new generation.

PJM proposes herein a series of decision-making criteria that could be utilized to “sort” this vast number of future possible scenarios into actionable forecasts of future needs and a reasoned justification for a directive to build new transmission, or upgrade existing transmission, via a new scenario-based transmission planning driver. The criteria would allow transmission planners to:

- Analyze the results and trends from the scenario studies
- Consider potential variations in the generation profile
- Establish a record of customer needs through surveys of actual customers and other means
- Ensure consideration of state policies and support from states for the overall implementation plan to effectuate those strategies
- Consider non-wires solutions, including grid-enhancing technologies that can enhance throughput of the existing grid or further utilize existing rights of way

The decision-making criteria would be applied transparently through the regional transmission planning processes to serve as a basis for directing the construction of new transmission to meet the future needs of load serving entities.

Finally, as PJM explained in its comments to FERC’s ANOPR, clear processes need to be established by the Commission to ensure that there is regulatory support for the specific results of the process through periodic “check-ins” to avoid constant re-litigation or later “second guessing” of decisions through contentious after-the-fact prudence reviews.

PJM suggests that a process be developed by the FERC to ensure that Planning Authorities can obtain approval by the regulator of the overall planning direction and the projects that are being considered in the context of the master plan. The ability to obtain periodic ‘check-in’s’ with the Commission, with input from all stakeholders, would (a) help to mitigate the risk of stranded costs from transmission projects that no longer have regulatory support and (b) would avoid the

overall plan and the key assumptions in the plan becoming the subject of constant litigation. PJM anticipates that such a regulatory process would allow for ‘mid-course correction’ with guidance provided by the FERC after input from all stakeholders.

In this paper, PJM presents its initial thoughts on taking the many commenter’s requests in the ANOPR for more robust long-range transmission planning to the next level by “drilling down” to address **how** a long-range planning process would lead to specific actionable steps in the development of an appropriate level of reliable and resilient transmission infrastructure.

II. Background

In the early 2000s, PJM experienced large west-to-east transfers, and was developing transmission expansion plans to mitigate voltage and thermal issues resulting from those transfers, affecting a number of congested lines in the traditional PJM footprint. In addition, PJM’s planning process was responding to steady load growth projections of 2–3% and experienced an all-time peak load of approximately 165 GW in 2006.

The 2008 recession and the Marcellus and Utica shale gas boom, which resulted in generation located much closer to the load centers, mitigated many of the reliability issues and the need to build new EHV transmission. Although all transmission strengthens the system to some degree, had PJM built large amounts of unneeded transmission, consumers may have been burdened with billions of dollars of unnecessary expenditures. Moving forward, a robust, scenario-based transmission planning criteria that analyzes an array of future generation expansion scenarios based on a documented record of customer needs and a series of regulatory “check-ins” can prudently establish “guard rails” that help avoid either overbuilding or underbuilding the future transmission system.

III. Guiding Principles

- 1 | Prudently use the transmission planner’s authority to order new transmission by focusing on serving identified customer needs while ensuring both that the reliability and resilience of the grid is maintained, and that there is not an unreasonable shift of costs or risks to end-use customers.
- 2 | The creation of scenarios should consider a number of input variables including a clear and defined record of customer needs through the planning horizon as well as other best information available.
- 3 | The choice among a host of future scenarios should be: (a) based on a clearly defined, robust set of scenario development criteria grounded in a record of customer needs and indicative interests within the planning horizon; (b) capable of adapting to an evolving set of future system conditions; and (c) crafted to foster the appropriate level of transmission expansion.

- 4 | In order to support transparency and reduce volatility within the planning process, the application of the scenario development criteria would form the basis for triggering the need for new long-lead-time transmission expansions. Specifically, the application of the criteria and choice of scenarios would drive:
 - a. Long-term conceptual design and Right-Of-Way (ROW) acquisition triggers near the end of the planning horizon
 - b. Short-, intermediate- and long-term triggers to determine when new needs are actionable
- 5 | PJM suggests that all transmission planners be required to develop a 15-year forward-looking master plan. The master plan is designed as a strategic planning document and is designed to guide and inform specific tactical studies at the intermediate-term (six to 10 years) and short-term (0 to five years) periods. The master plan should enable identification of potential long-lead transmission needs as they first begin to materialize. Clearly, to the extent that the 15-year-out review identifies issues that require a resolution that would require a very large project that would take years to bring into service, the 15-year master plan could include such plans in the final transmission plan. More likely, even large projects would require a time frame that would be more compatible with the intermediate- and short-term tactical analysis. Accordingly, the master plans developed by transmission planners should provide clear criteria for determining the “triggers” as to when competitive solicitations for projects should commence versus waiting until some of the uncertainties associated with future system topology, congestion and public policy are further clarified, so that the planners could “right size and locate” the needed transmission developments based on more certain nearer-term information. This approach will not only help inform the near-term development needs and align those with potential future expansions, but will also allow for reasonable staging of capital investment in a staged manner that is triggered based on well-defined milestones. This approach will also assist and guide future generation developers on the longer transmission expansion plans and hence strategically align their planned developments with efficient, well designed and ready-to-execute transmission capability additions.
- 6 | The longer-term planning scenario studies that identify and trend future needs, and the subsequent application of the decision-making criteria through the master plan development process, will in turn inform and support the intermediate-term (six to 10 years) and short-term (one to five years) planning timelines when trends of recurring needs become more actionable.

IV. Solution Details

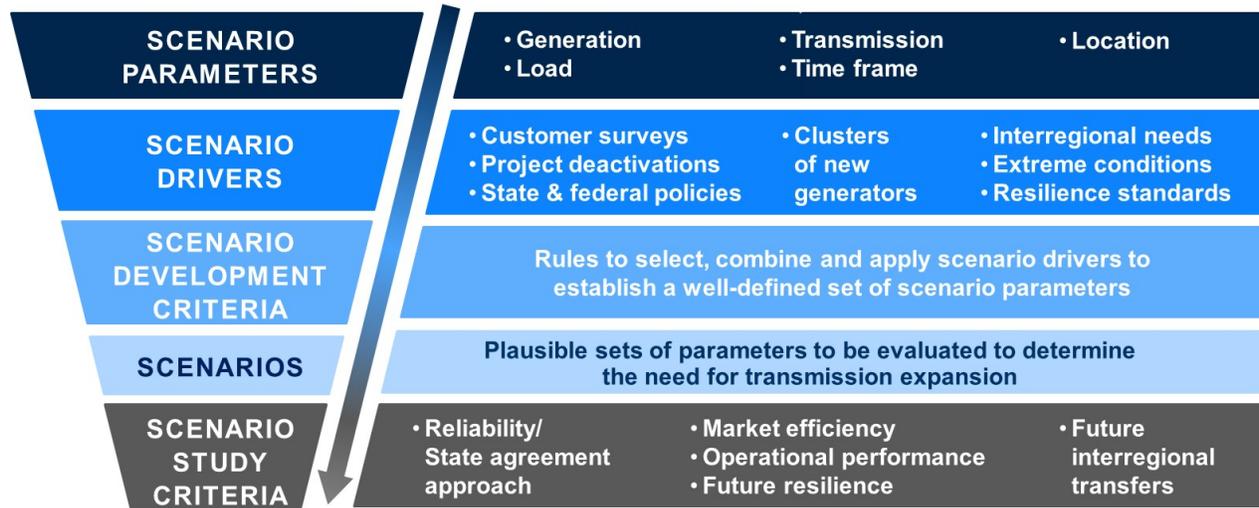
Scenario-based transmission planning will help highlight areas of the system that may experience increased transfers and subsequent transmission criteria violations, providing

advanced situational awareness of potential needs for required system reinforcements. The following scenario terminology definitions help provide context as the terminology is repeated throughout this white paper.

- **Scenario parameters** are building blocks that are defined in order to construct a scenario.
- **Scenario drivers** are those factors that impact scenario parameters.
- **Scenario development criteria** are the rules by which the scenario drivers are selected.
- **Scenario** is a plausible set of parameters to be evaluated as part of power flow base case.
- **Scenario study criteria** are the methodologies by which the scenario is analyzed including the decision-making process that determines whether potential reliability violations warrant transmission expansion.

At a high level, scenarios are developed by defining input parameters and associated thresholds based on a set of drivers. Predefined study criteria are then applied to a plausible subset of scenarios. The Scenario-Based Transmission Planning graphic summarizes the scenario planning process. Additional details follow in sections A through E.

Figure 1. Scenario-Based Transmission Planning



A. Scenario Parameters

The first step in scenario-based transmission planning is to define the basic set of parameters to consider in each scenario that will constitute a potential need for transmission expansions. The parameters can be distilled into five essential categories:

- Time frame

- Geographic and electrical location
- Generation
- Load and
- Transmission topology

However, there are numerous considerations within each category and numerous factors or drivers that influence how these categories should be configured, and, frequently, there is a many-to-one relationship between the categories and the drivers that influence them.

PJM currently considers years six to 15 in its intermediate-term (six to 10 years) and long-term (10 to 15 years) planning studies and feels that these are appropriate time frames to consider. For the PJM system, these time frames strike a proper balance between the time required to construct long-lead-time transmission expansions and the uncertain nature of input variables that drive such expansions in further-out years. Currently, PJM uses reliability study results from the five-year short-term studies to extrapolate projected load growth through year 15.

B. Scenario Drivers

Below is a suggested list of scenario-based transmission planning drivers that PJM will consider for a long-term 15-year time frame set of scenario studies to expand upon the assumptions currently used in developing the long-range planning solutions.

Scenario-Based Transmission Planning Drivers

- Electric load trends in the residential, commercial and industrial areas
- State & federal policy; documented input on state plans to meet policy
- Documented record of customer needs developed through surveys and other means; customer survey trends and goals (including identification of existing and potential future PPA sources, DER plans of local governments etc.)
- Future generation interconnections, including input from states considering siting concerns
- Future generation deactivations/retirements
- Interregional transfers and criteria

C. Scenario Development Criteria

Deterministic vs. Probabilistic Analysis and Potential Application of Each

The scenario development criteria will specify the parameters to consider for each scenario driver, determine how the various drivers should be considered in relationship to one another, and determine which of the various scenarios should be selected. The scenario study criteria

will provide the methodology by which the scenario is analyzed as well as the decision-making process that determines whether the scenario study results warrant the addition of a new, or the removal of, approved transmission expansion. Criteria for selecting which scenarios will trigger the need for transmission expansions can be either deterministic or probabilistic. In practice, there will need to be some combination of the two given that certain variables and assumptions in scenario development, and triggers for new transmission expansions, may more naturally align with a probabilistic approach and others with a deterministic approach.

For example, PJM annually assigns generation in the PJM interconnection queue a probability that the proposed generation will achieve commercial operation. Such statistics could be used to develop metrics that quantify the probability of a transmission need. A similar statistic could be developed for future generator deactivations based on the history of the unit's participation in the various PJM markets, information as to whether the unit's costs are covered under long-range contracts or state legislative programs, and the "net revenue" analysis undertaken by the IMM. However, other variables in the planning process, such as state and federal policies, appropriate levels of interregional transfers, and certain extreme events, may lend themselves more to a deterministic treatment.

PJM envisions that a hybrid criteria and set of thresholds for triggering transmission expansions based on both probabilistic and deterministic considerations will be necessary to properly account for the myriad different variables that need to be considered in a robust, long-term transmission expansion planning process. This criteria and associated thresholds will need to be well defined and vetted with stakeholders. Ultimately, the decision-making criteria will be designed to support a transparent, repeatable transmission planning process that values the above information as well as stakeholder and policymaker input.

As the RTEP process moves from the long-term, to intermediate, to short-term timeframe, scenarios associated with each subsequent timeframe should be informed by the evolution of identified trends.

D. Examples of Scenario Study Criteria

Below are the general types of scenario study criteria that PJM currently has utilized in the planning process.

- NERC and PJM reliability criteria (including State Agreement Approach)
- Market efficiency (persistent congestion)
- Operational performance
- Future resilience: FERC-defined resilience criteria – CIP 14 facilities elimination and extreme weather analysis
 - CIP 14 facility elimination

- Storm hardening based on extreme weather events
- Storm hardening to protect against “extreme weather” events
- Identification of infrastructure most vulnerable to flooding or other weather-related events
- Identification of infrastructure that could be most impacted by a cybersecurity event
- Future interregional transfer capability
- Identification of locations on the grid where a more robust solution could address a cluster of interconnection requests
- Development of holistic solutions to tangible recurring issues, such as the conversion of multiple 138 kV aging facilities to 230 kV facilities as a means to address similar violations within a common electrical area multiple years in a row
- National interest transmission corridors developed by DOE

E. Scenario Example

PJM sets forth below an example of how drivers, scenario development criteria and scenario study criteria would work together to address a specific resilience issue using the “inverted pyramid” structure set forth above.

- ***Step One – Identification of a Specific Scenario Driver:*** In this example, PJM, working with stakeholders, would have developed a specific resilience driver focused on substation resilience. For example, the driver could be focused on ensuring no adverse reliability impact from the loss of an entire substation.
- ***Step Two – Application of Scenario Development Criteria:*** In this step, PJM would test the above primary scenario driver as well as other identified scenario drivers utilizing standard and extreme forecast conditions for the planning horizon.

- ***Step Three – Utilization of Scenario Study Criteria:***

At this stage, PJM would analyze the impact to reliability on the scenario developed by applying the scenario development criteria in order to determine whether some ameliorative action was warranted. To undertake this step, PJM would:

- Identify potential reliability violations resulting from the loss of an entire substation using a probabilistic cascading trees analysis
- Identify reliability violations that are identified with a frequency of greater than X% that require mitigation measures

- **Step Four – Identify if Scenario Results Are Actionable and Determine Required Time Frame:**

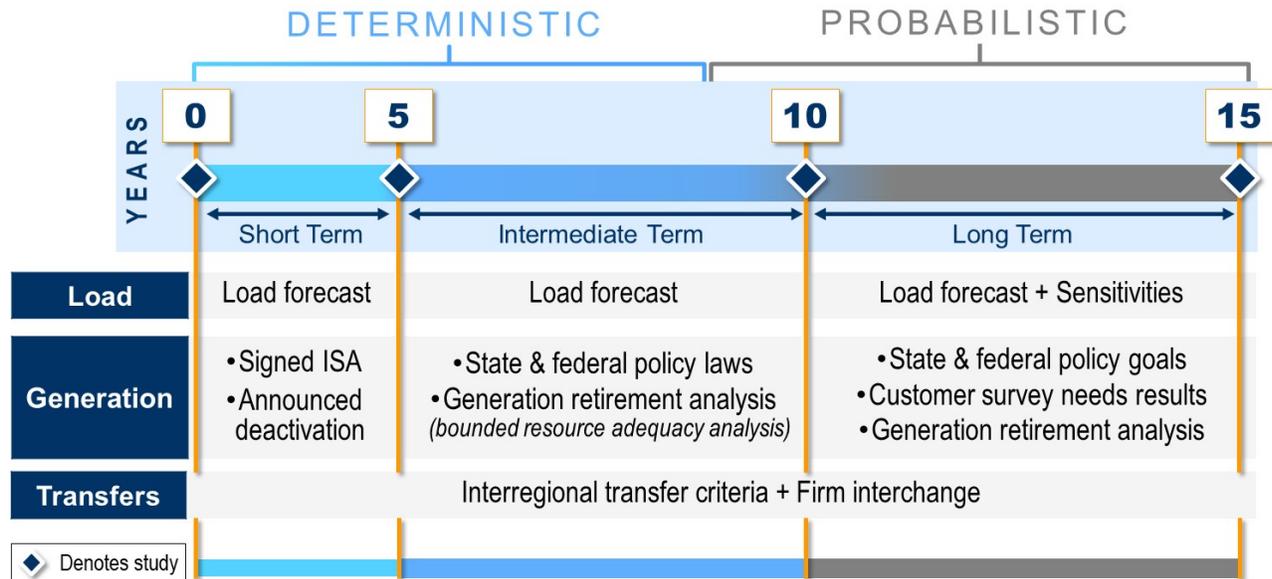
- Depending on the nature and severity of the violations resulting from the above analysis, PJM would consider whether and when the issue would need to be addressed consistent with established criteria by examining:
 - The severity and risk indicated from the above analysis to include voltage level, magnitude of violation and frequency of violation
 - Whether the severity and risk exists only in the long term but also in the short term
 - The probabilities of intervening changes in system topography or market solutions that would ameliorate or eliminate the risk
 - An analysis of potential solutions and expected time frames for planning, siting and construction of such solutions

In summary, PJM would determine whether the long-term plan analysis results would remain on a “watch list” for future review, designed to be actionable on a defined trigger, or would be immediately actionable. A predefined methodology/metric or trigger would need to be developed in order to determine when identified needs based primarily on probabilistic analysis require immediate action. The transmission development plan may also utilize risk mitigation measures that allow larger transmission development need drivers to be well established before initiating major development activities.

V. Transition to the Intermediate- and Short-Term Planning Time Frames

The 15-year long-term analysis results will inform stakeholder discussions, future development interests, and set in motion the review of potential solutions as input assumptions become more certain as part of the intermediate- and short-term planning analysis. For example, the identification of similar violations within a common electrical area multiple years in a row would allow transmission planners to identify more holistic solutions, such as the conversion of multiple 138 kV aging facilities to 230 kV facilities as violations are identified in the intermediate-term analysis. The development of the scenarios for both the long-term and intermediate-term studies should be limited to a set of approximately three scenarios for consideration.

Figure 2. Planning Time Frame Details



The intermediate-term analysis should be more deterministic in nature and more informed by established state and federal laws that are actionable, not generic policies or goals. Scenarios would reflect a level of projected future renewables that is bounded by resource adequacy requirements (i.e., load plus required reserve requirements). The generator retirement analysis would reflect state and federal laws that are actionable, not generic policies or goals, and include a well-defined generation retirement economic analysis. To the extent possible, replacement generation would be selected from the PJM interconnection queue. The incorporation of additional generation beyond the interconnection queue may be necessary to ensure planning considers generation that would be required to meet state and federal requirements. Generally, the intermediate-term study includes the following input drivers:

- 1 | PJM load forecast, which includes residential, commercial and industrial load projections
- 2 | State and federal policy laws
- 3 | Customer survey trends and goals [including identification of existing and potential future Purchase Power Agreement (PPA) sources, distributed energy resources (DER) plans of local governments, etc.]
- 4 | Generation interconnections including DER
- 5 | Results of generation retirement analysis (driven by state laws and economic analysis)
- 6 | Interregional criteria

Once the scenario is developed, PJM can apply its scenario study criteria (suite of existing planning tests to perform the planning assessment).

The short-term planning time frame (0 to five years) analysis would need to consider trends identified in the intermediate timeframe.

As described in detail above, PJM presents this white paper in order to further flush out the “how to proceed” issues that have been prompted by the various comments submitted in the ANOPR and to prompt discussion among states and stakeholders on this next level of decision-making. PJM looks forward to dialogue, thoughts, and reactions from all affected stakeholders to the concepts raised in this white paper.

ATTACHMENT C

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Building for the Future Through)
Electric Regional Transmission)
Planning and Cost Allocation and)
Generator Interconnection)**

Docket No. RM21-17-000

REPLY COMMENTS OF PJM INTERCONNECTION, L.L.C.

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On behalf of PJM Interconnection, L.L.C.

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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Building for the Future Through)	Docket No. RM21-17-000
Electric Regional Transmission)	
Planning and Cost Allocation and)	
Generator Interconnection)	

REPLY COMMENTS OF PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. (“PJM”) hereby submits the following reply comments¹ in response to select issues raised in initial comments on the Notice of Proposed Rulemaking (“NOPR”) issued by the Federal Energy Regulatory (“Commission” or “FERC”) in the above-captioned docket.² PJM does not respond to each of the numerous issues raised in the approximately 200 sets of comments filed in response to the NOPR. Rather, PJM limits these reply comments to:

- (i) emphasizing the issues on which PJM believes the Commission should focus as this proceeding moves forward to a Final Rule;
- (ii) responding to factual inaccuracies or providing clarification about PJM’s processes in response to other commenters’ filings; and
- (iii) addressing proposals suggested by other commenters about which PJM agrees, has concerns, or finds would be unworkable in the PJM Region.

¹ PJM submitted initial comments in this proceeding on August 17, 2022. See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (“RM21-17”), Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000 (Aug. 17, 2022) (“PJM Initial Comments” or “PJM’s Initial Comments”).

² *RM21-17, Notice of Proposed Rulemaking*, 179 FERC ¶ 61,028, 87 Fed. Reg. 26,504 (May 4, 2022) (“NOPR” or “LTRTP NOPR”).

I. OVERVIEW OF PJM’S RECOMMENDATIONS IN THIS PROCEEDING

As stated in its Initial Comments, PJM generally supports the Commission’s proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by “changes in the resource mix and demand” (referred to herein as “Long-Term Regional Transmission Planning”). That said, as PJM emphasized in its Initial Comments, as well as in other filings responding to other recently-issued Notices of Proposed Rulemaking,³ PJM believes that it is essential that any future rule in this docket (“Final Rule”) factor resilience into revisions to intermediate-term and Long-Term Regional Transmission Planning processes.⁴ To that end, PJM proposed a comprehensive proposal to serve as a roadmap for how the Commission should address the concept of “Enhanced Reliability.”⁵ PJM also highlighted several other specific issues that the Commission should prioritize as it considers appropriate planning reforms to be included in the Final Rule. Below, PJM further: (i) elaborates on its Enhanced Reliability proposal, and (ii) summarizes the other issues that PJM (and other parties) believe the Commission should focus on as it develops the Final Rule.

³ See *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (2022) (referred to herein as the “Extreme Weather NOPR”); *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, 179 FERC ¶ 61,196 (2022) (referred to herein as the “Informational Reports NOPR”). Together with the LTRTP NOPR that is the subject of these comments, the Extreme Weather NOPR and the Informational Reports NOPR are collectively referred to as the “Transmission Planning NOPRs.”

⁴ See *RM21-17*, PJM Initial ANOPR Comments, at 27-41 (Oct. 12, 2021); *RM21-17*, PJM ANOPR Reply Comments, at 7-10 (Nov. 30, 2021).

⁵ As set forth in its Initial Comments, PJM proposes to define “Enhanced Reliability” as “[t]he ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.” PJM uses this term rather than the term “resilience,” given concerns raised by some regarding the use of the term “resilience” and its being confused with a prior Department of Energy (“DOE”) proposal, long since rejected by the Commission.

A. PJM Responds to Inquiries Regarding PJM’s Enhanced Reliability Planning Proposal

In PJM’s Initial NOPR Comments, as well as its comments submitted in response to the other Transmission Planning NOPRs,⁶ PJM outlined a proposed “roadmap” pursuant to which the Commission could holistically and comprehensively address the need for Enhanced Reliability measures on both a regional and interregional level.⁷ In response to comments and questions that have since arisen, PJM summarizes below:

- the legal authority pursuant to which the Commission can address Enhanced Reliability-related issues using authority beyond its more limited Federal Power Act (“FPA”) section 215⁸ authority to review North American Electric Reliability Company (“NERC”) standards;
- the tie between PJM’s Enhanced Reliability proposal and issues already raised in the various Transmission Planning NOPRs;
- the record support for PJM’s proposals;
- the relationship between moving forward on Enhanced Reliability planning and: (i) the need for not disturbing existing short-term planning processes⁹ and (ii) the LTRTP NOPR’s

⁶ See PJM Initial NOPR Comments at 11-25. See also *Transmission System Planning Performance Requirements for Extreme Weather*, Comments of PJM Interconnection, L.L.C., Docket No. RM22-10-000, at 2-4 (Aug. 26, 2022) (“PJM Extreme Weather Comments”); *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, Comments of PJM Interconnection, L.L.C., Docket Nos. RM22-16-00, *et al.*, at 3-4 (Aug. 30, 2022) (“PJM Informational Reports Comments”).

⁷ PJM Initial Comments at 11-25, 66-67 and 123-125.

⁸ 16 U.S.C § 824o(d)(5).

⁹ See NOPR at P 72 (“With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000’s requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability and economic requirements”). For purposes of PJM’s comments in this docket, PJM focuses on three different planning horizons within the planning process: (i) the present five-year forward planning horizon to address short-term reliability and market efficiency needs, which PJM describes herein as “short-term planning;” (ii) the six- to 15-year analysis that PJM undertakes today to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation, and broader generation development patterns, including renewable resources and storage technologies that may be under development, which PJM describes herein as “intermediate-term planning;” and (iii) the NOPR’s proposed 20-year long-term planning process, which PJM describes herein as “Long-Term Regional Transmission Planning” (the term the Commission uses in the NOPR). In the future, these three planning horizons will inform each other, just as the existing short-term planning and intermediate-term planning processes do today.

focus on transmission development to meet the changing resource mix driven by state and federal public policy; and

- PJM’s specific requests to ensure that the Enhanced Reliability issue is appropriately addressed.

Legal Authority: In Section II.A.7 of its Initial NOPR Comments, PJM detailed the legal authority pursuant to which the Commission can implement the initiatives that PJM proposed in this docket (and raised in each of the other dockets as well). Although directing NERC to develop standards pursuant to FPA section 215 is one regulatory tool, it is not the only regulatory tool to address Enhanced Reliability planning.¹⁰ Moreover, for the reasons PJM detailed in its Extreme Weather Comments in Docket No. RM22-10, use of the NERC process and the adoption of standards is notably a sub-optimal tool to utilize at this early stage.¹¹

The Commission clearly has authority over just and reasonable rates, and terms and conditions of public utility service. Although at first blush that may lead to the view that any initiative has to directly involve rate setting, Congress made clear through the Energy Policy Act of 2005¹² and FPA section 217(b)(4)¹³ that planning to meet the needs of load serving entities is an integral part of the Commission’s responsibilities under the FPA. Thus, the topic of Enhanced Reliability touches several aspects of the Commission’s jurisdiction: reliability (FPA section 215), wholesale rates (FPA sections 201, 205), Congressional directives to ensure that planning meets

¹⁰ See PJM Extreme Weather Comments at 3-5.

¹¹ *Id.*

¹² Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005); *id.* at § 1233(a) (adding FPA § 217(b)(4)).

¹³ 16 U.S.C. § 824q (“The Commission shall exercise the authority of the Commission 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...***”) (emphasis added).

the needs of load serving entities (FPA section 217(b)(4)), and transmission (FPA sections 201, 205).

In short, Congress has made the link between planning and the Commission's responsibilities under FPA sections 201, 205, 216 and 217(b)(4) by noting that in exercising its authority, the Commission "*shall ... facilitate[] the **planning** and expansion of transmission facilities to meet the **reasonable needs of load-serving entities to satisfy the service obligations of load serving entities***" (emphasis added).¹⁴ Although the statute goes on to discuss availability of long term financial transmission rights, a directive to the Commission to expand planning so as to ensure that it facilitates load serving entities meeting their service obligations to load was a key component of the legislation and the genesis of this very section of the FPA.

PJM wishes to underscore that it is *not* seeking a directive from the Commission to order transmission to be built. Such provisions already exist in the authority that transmission owners have granted to Regional Transmission Organizations ("RTOs") through their governing documents,¹⁵ and utilities in non-RTO areas already have obligations under state law to build to meet the needs of retail customers in their footprint (essentially paralleling the directive Congress granted to the Commission through FPA section 217(b)(4)).¹⁶ Rather, PJM requests that the Commission utilize its authority over planning to ensure that enhanced reliability planning is undertaken in the intermediate and long term. Enhanced Reliability is clearly integral to the needs

¹⁴ *Id.*

¹⁵ *See, e.g.*, PJM Consolidated Transmission Owner Agreement ("CTOA"), Articles 4.1.4 (Planning Information) and 4.2 (Obligation to Build); New York Independent System Operator and Transmission Owners, section 3.10(d) and (e); and Independent System Operator - New England, Transmission Owner Agreement, Article 3.09 and Schedule 3.09(a) and Open Access Transmission Tariff, Attachment K, section 8.

¹⁶ Under state statutes, transmission owners are obligated to provide safe and reliable service to their native load customers.

of load-serving entities and, through those load-serving entities' service obligations, to ultimate end use customers.

The Relationship between Enhanced Reliability and Issues Raised in the LTRTP

NOPR: The Transmission Planning NOPRs begin to address the elements of Enhanced Reliability, though, in PJM's view, they do so in a more piecemeal approach. Nevertheless, the LTRTP NOPR *already* has introduced this topic by proposing transmission providers to consider among the Factors used to develop Long-Term Scenarios both (i) mitigation of extreme events and system contingencies and (ii) mitigation of weather and load uncertainty.¹⁷ As a result, this is not a new topic in this docket or in the other related dockets.

Similarly, the Extreme Weather NOPR has introduced planning for hot and cold temperatures (one aspect of Enhanced Reliability planning) as a topic that needs immediate Commission action. In addition, through the Informational Reports NOPR, the Commission will have before it a record as to the steps that Balancing Authorities are taking to address extreme weather both from a planning and operations viewpoint. In short, the Commission has already brought this subject into each of the Transmission Planning NOPRs. PJM is simply proposing a more comprehensive approach to connect those threads found in each of these dockets by instead proposing that the Enhanced Reliability issue be addressed comprehensively, rather than a piecemeal approach.

Record Support for PJM's Enhanced Reliability Proposal: There is extensive support in the record for PJM's Enhanced Reliability proposal upon which the Commission can rely to address these issues more comprehensively in this docket. For one, PJM detailed the specific facts

¹⁷ See LTRTP NOPR at P 104.

that gave rise to these recommendations and a detailed list of those recommendations in the Commission’s record in the Commission in Docket No. AD18-7-000 (the “RTO/ISO Resilience Proceeding”).¹⁸ As PJM explained, both the Commission and individual Commissioners noted that although the Commission was closing the RTO/ISO Resilience Proceeding, it was not rejecting the record in that case or finding that the issue did not require action. Specifically, while the Commission did not take any particular action based on the record, it stated that ***“the resilience and reliability of the bulk power system must—and will—remain one of the Commission’s paramount responsibilities and concerns.”***¹⁹ Similarly, Commissioners Christie and Clements in their concurrence stated that ***“[t]he issues attendant to grid resilience and reliability that this particular proceeding raised are compelling and must command this Commission’s future attention.”***²⁰

By the same token, PJM has previously provided the Commission information regarding its annual fuel security analysis to identify any risks to grid reliability that can result from prolonged extreme weather, coupled with fuel unavailability.²¹ Similarly, the U.S. Department of

¹⁸ See PJM Initial NOPR Comments, Section II.A.

¹⁹ *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,111, at P 4 (2021) (“Order Terminating Resilience Proceeding”).

²⁰ Order Terminating Resilience Proceeding, Christie and Clements Concurring opinion at P 1 (emphasis added).

²¹ See, e.g., *Climate Change, Extreme Weather, and Electric System Reliability*, Docket No. AD21-13-000, Post-Technical Conference Comments of PJM Interconnection, L.L.C., at 16-17 (explaining PJM’s Fuel Security Initiative, which is an annual Fuel Security analysis to identify any risks to grid reliability that can result from prolonged extreme weather, coupled with fuel unavailability); PJM Extreme Weather Comments at 11. See also, e.g., PJM Interconnection, L.L.C., *PJM’s Evolving Resource Mix and System Reliability* (Mar. 30, 2017), <https://www.pjm.com/~media/library/reports-notice/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx>; PJM Interconnection, L.L.C., *Fuel Security – Analyzing Fuel Supply Resilience in the PJM Region* (Nov. 1, 2018), <https://www.pjm.com/~media/committees-groups/committees/mrc/20181101-fuel-security/20181101-pjm-fuel-security-summary.ashx>; PJM Interconnection, L.L.C., *Fuel Security Monitoring Methodology* (June. 10, 2021), <https://www.pjm.com/~media/committees-groups/committees/oc/2021/20210610/20210610-item-13-fuel-security-monitoring-methodology.ashx>, and PJM’s related presentation to the Operating Committee, <https://www.pjm.com/~media/committees-groups/committees/oc/2021/20210715/20210715-item-08-fuel-security-update.ashx>.

Energy (“DOE”) included in the record a long list of studies, which include studies that directly analyze the reliability impacts of the changing resource mix *across the nation*.²² Moreover, (a) the comments submitted by parties in the Extreme Weather NOPR docket;(b) the soon-to-be submitted informational reports on extreme weather; and (c) other parties’ comments on the Factors to be considered as part of the Long-Term Regional Transmission Planning process, all provide record support for the Commission to ensure, through specific actions as detailed below, that Enhanced Reliability is addressed.

The Relationship of Enhanced Reliability Issues to the Other NOPR Initiatives: PJM wishes to underscore that its Enhanced Reliability proposal is *additive to, rather than a substitute for*, the proposed Long-Term Regional Transmission Planning processes set forth in the LTRTP NOPR. PJM has proposed specific rule language to ensure that Enhanced Reliability is included in the planning process.²³ In addition, as summarized below, PJM requests that in the Final Rule the Commission underscore its continued focus on these issues and the need for them to be addressed, as well as its using its convening authority to bring together entities such as the DOE National Laboratories, Interconnection-wide planning entities like the Eastern Interconnection Planning Collaborative and the Western Electricity Coordinating Council, NERC, and the National Association of Regulatory Utility Commissioners (“NARUC”), so that their actions complement rather than disturb the other actions of the Commission to encourage enhanced long range planning consistent with its NOPR proposals.

²² See *RM21-17*, Comments of the United States Department of Energy to Notice of Proposed Rulemaking (Aug. 17, 2022).

²³ See PJM Initial Comments, Appendix A.

PJM recognizes that the tasks already assigned under the LTRTP NOPR are substantial. However, in PJM’s view it would not be prudent to set requirements for forward planning that do not address the Enhanced Reliability issue. Nothing in PJM’s proposal changes any of the remaining aspects of the NOPR concerning Long-Term Regional Transmission Planning, most of which PJM supports as explained in PJM’s Initial Comments.

PJM’s Specific Requests: To reiterate, PJM requests that the Commission stitch together the threads of Enhanced Reliability that are now sprinkled through several NOPRs and assigned to different entities. PJM has proposed a “roadmap” that includes the following affirmative steps that it requests that the Commission undertake:

- Adopt the proposed language changes set forth in PJM’s Initial Comments, including (i) PJM’s proposed revisions to Attachment K of the Commission’s *pro forma* OATT in the Final Rule and (ii) PJM’s proposal to add additional Factors to be considered in the development of Long-Term Scenarios, so that there is clarity that Enhanced Reliability planning is a key component of Long-Term Regional Transmission Planning;
- Make clear in its Final Rule that Enhanced Reliability is a vital component of planning on which the Commission intends to focus, and for which it will be reviewing individual transmission planner and interregional efforts;
- Challenge the industry to submit action plans on the various issues related to Enhanced Reliability that different transmission providers see as needed in their footprint; and
- Use its convening authority to bring together the industry, NERC, NARUC, *et al.*, on issues which are interregional- or interconnection-wide in nature where common metrics and methodologies should be developed to ensure that solutions recognize the interconnected and co-dependent nature of each Planning Authority within its respective Interconnection.

B. PJM Highlights Other Areas on Which the Commission Should Focus in the Final Rule

In addition to Enhanced Reliability, PJM requests that the Commission prioritize the following specific issues as it considers appropriate planning reforms to be included in any Final Rule in this docket:

- **Lessons Learned from the Order No. 1000 Compliance Process:** There is near unanimous agreement among Regional Transmission Organizations (“RTOs”), Independent System Operators (“ISOs”) and other regional planning organizations that the Commission must consider “lessons learned” when directing any compliance process arising out of the Final Rule.²⁴ A number of other commenters similarly urged the Commission to avoid mandating an overly prescriptive planning process, and to allow for flexibility that recognizes regional differences.²⁵ The Order No. 1000²⁶ compliance process was extremely resource-intensive and litigious, which, in turn, delayed implementation of Order No. 1000 reforms across the country.²⁷ PJM urges the Commission to: (i) consider the comments of RTOs and ISOs, who will be the parties implementing any reforms set forth in a Final Rule, (ii) avoid overly-prescriptive requirements to implement the Long-Term Regional Planning process, consistent with the compliance proposal set forth in PJM’s Initial Comments,²⁸ and (iii) consider PJM’s proposed solution for avoiding a litigious, elongated and disparate compliance process.²⁹
- **Include a Uniform, Nationwide Decision Regarding the Federal Right of First Refusal:** As PJM³⁰ and others³¹ argued, it would be inappropriate to take a region-by-region

²⁴ *RM21-17*, Initial Comments of the ISO/RTO Council, at 1-5, 9 (Aug. 17, 2022); *RM21-17*, Comments of the Midcontinent Independent System Operator, Inc., at 2-5 (Aug. 17, 2022) (“MISO Initial Comments”); *RM21-17*, Comments of the New York Independent System Operator, Inc., at 10-11 (Aug. 17, 2022); *RM21-17*, Comments of the California Independent System Operator Corporation on Notice of Proposed Rulemaking, at 1-4 (Aug. 17, 2022) (“CAISO Initial Comments”); *RM21-17*, Initial Comments of ISO New England Inc., at 4-5 (Aug. 17, 2022) (“ISO-NE Initial Comments”); *RM21-17*, Southeastern Regional Transmission Planning Process Sponsors’ Initial Comments, at 3-4 (Aug. 17, 2022).

²⁵ *See, e.g., RM21-17*, Comments of the Organization of PJM States, Inc., at 4 (Aug. 17, 2022) (“OPSI Initial Comments”); *RM21-17*, Comments of the National Association of Regulatory Utility Commissioners, at 9 (Aug. 17, 2022) (“NARUC Initial Comments”); *RM21-17*, Comments of the Public Utilities Commission of Ohio’s Office of the Federal Energy Advocate, at 23 (Aug. 17, 2022); *RM21-17*, Comments of the Pennsylvania Public Utility Commission, at 6 (Aug. 17, 2022).

²⁶ *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh’g*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh’g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff’d sub nom., S.C. Pub. Serv. Auth. v. F.E.R.C.*, 762 F.3d 41 (D.C. Cir. 2014).

²⁷ As PJM explained in its Initial NOPR Comments, the Order No. 1000 compliance process delayed the implementation of the Order No. 1000 reforms across the country. In addition, there remain marked differences in the level of compliance across the nation, with PJM opening 28 competitive windows while other regions, and particularly, non-RTO regions, have yet to hold a single competitive window. *See* PJM Initial NOPR Comments, section III.C.

²⁸ *See* PJM Initial Comments, Section II.B and Appendix A. PJM emphasizes that its proposed solution for avoiding a litigious compliance process is intended to apply to Long-Term Regional Transmission Planning processes.

²⁹ *See id.*, Section II.B.

³⁰ *See id.*, Section II.C.

³¹ *See, e.g., RM21-17*, Comments of LS Power Grid, LLC to the Commission’s Notice of Proposed Rulemaking, at 73-76 (Aug. 17, 2022) (“LS Power Initial Comments”).

approach to reinstating the federal right of first refusal.³² Rather, because the Commission eliminated the federal right of first refusal on a nationwide basis in Order No. 1000, the decision about whether to reinstate the federal right of first refusal must be made by the Commission on a nationwide basis.³³ However, some commenters recommend that the Commission adopt a “state ‘opt-in’ approach for the elimination of the [right of first refusal].”³⁴ As a practical matter, there is no need for the Commission to address this proposal. Instead, PJM lays out below an alternative approach, grounded in today’s planning practices, that respects and gives full effect to both state and federal authority in this area. Moreover, as PJM explains below, there are unaddressed legal and practical questions as to how proposals for a “hard-wired” opt in or opt out would work in practice that the Commission would need to address were it to pursue this approach.³⁵

- **Equitable Treatment Between RTO/ISO and Non-RTO/ISO Regions:** Changes to the resource mix and demand are not limited to RTO/ISO regions. Therefore, as PJM³⁶ and others³⁷ explained, the Commission should ensure equitable treatment as between RTO/ISO and non-RTO/ISO regions.
- **Common Measures of Interregional Transfer Capability:** As PJM³⁸ and many others have noted in this proceeding and in other ongoing Commission proceedings,³⁹ the Commission should act more decisively now to prepare for the future trends and needs associated with the evolving resource mix and increasing frequency of extreme weather events by driving the development of a robust standardized minimum interregional transfer capability methodology. Specifically, PJM continues to embrace the development of common

³² See PJM Initial Comments, Section II.C. PJM clarifies below some of the data presented by other parties regarding the current state of competition in their arguments regarding the federal right of first refusal. See Section II.B, below.

³³ See LS Power Initial Comments at 73, n.235 (noting “Order No. 1000-A rejected calls for regional differences to the removal of the federal right of first refusal”).

³⁴ See MISO Initial Comments at 21. See also *RM21-17*, Comment of Harvard Electricity Law Institute, at 5-6, 31-33 (Aug. 17, 2022) (“Harvard Initial Comments”).

³⁵ See Section III.A, *infra*.

³⁶ See PJM Initial Comments, Section I.

³⁷ See, e.g., Transmission Access Policy Study Group Comments at 68-69.

³⁸ See PJM Initial Comments, Section III.F.

³⁹ See, e.g., *RM21-17*, Initial Comments of the Edison Electric Institute, at 47-48 (Aug. 17, 2022) (“EEI Initial Comments”); *RM21-17*, Initial Comments of American Electric Power Service Corporation, at 17-18 (Aug. 17, 2022); See also *Joint Federal-State Task Force on Electric Transmission*, Fourth Meeting Transcript, Docket No. AD21-15-000, at 13 (July 20, 2022) (“Transcript”) (Chairman French: “There is overwhelming and continually growing body of evidence that materially expanding import and export capabilities among the regions will produce immense economic reliability and public policy benefits, and adding this extra transmission capacity to our grid will help solve the long-term planning and generator interconnection challenges that we face as well”); *id.* at 15 (Commissioner Brown Dutrieuille: “the most important interregional transmission opportunity ... may be to increase the transfer capacity between the regions.... The next step would be to study what kind of future transfer capacity will be necessary based on a diverse range of planning scenarios, and I see the need for two studies. One for the present, and one for the future, but both studies should utilize a diverse set of planning scenarios”).

measures of interregional transfer capability across the seams through a process that includes: (i) Commission support for enhanced reliability steps to be taken by each region and (ii) the Commission using its convening authority to bring together the industry, NERC, NARUC, DOE and its National Labs in a concerted effort to tackle this larger issue.

II. CLARIFICATION OR CORRECTION OF STATEMENTS IN OTHER PARTIES' COMMENTS

A. PJM Provides Clarification Regarding the Planning Community Tool Used as Part of the PJM Transmission Owners' Attachment M-3 Process

In the NOPR, the Commission proposes reforms that would require transmission providers to include a planning process providing for additional transparency into transmission owners' local transmission planning processes in order to better facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than the proposed local transmission facilities.⁴⁰ The Commission proposes a process that largely mimics the PJM Transmission Owners' "Attachment M-3 Process,"⁴¹ which the Commission has found to be a transparent, iterative planning process that affords stakeholders meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process.⁴²

⁴⁰ PJM Transmission Owners plan Supplemental Projects that address a need to expand or enhance transmission facilities where the responsibility for planning to address such needs has not been transferred to PJM pursuant to the CTOA. Supplemental Project planning is conducted under PJM Tariff, Attachment M-3.

⁴¹ NOPR at P 400.

⁴² PJM Tariff's local planning processes providing for review of Attachment M-3 Projects that include, among other things: (i) review of Attachment M-3 Projects that allows the Subregional RTEP Committees to have a meaningful opportunity to participate and provide feedback, including written comments for Attachment M-3 Projects; (ii) review transmission owner's criteria, assumptions and models through a minimum of one Subregional RTEP Committee meeting; (iii) schedule a minimum of one Subregional RTEP Committee meeting per planning cycle to review identified criteria violations and resulting system needs; (iv) schedule a minimum of one Subregional RTEP Committee per planning cycle to review potential solutions for identified criteria violations, as well as any alternative solutions identified by transmission owners or stakeholders; and (v) each transmission owner will finalize for submittal to the transmission provider Attachment M-3 Projects for inclusion in the Local Plan. Tariff, Attachment M-3, section (c).

In its comments, American Municipal Power, Inc. (“AMP”) makes several misleading and inaccurate statements about the PJM Planning Community tool used as part of the PJM Transmission Owners’ Attachment M-3 Process to support its argument that the Attachment M-3 Process should not be applied nationwide.⁴³ PJM responds to AMP’s misleading and inaccurate statements below.

First, AMP suggests that the Planning Community tool deprives stakeholders from having meaningful opportunities to participate in the PJM Transmission Owners’ Attachment M-3 Process, because the PJM Transmission Owners are not required to provide responses to questions submitted through the tool.⁴⁴ AMP suggests that the Planning Community tool is nothing more than a “deposit of superfluous information on a web portal, without explanation or response to feedback.”⁴⁵ This is categorically untrue.

The PJM Planning Community tool was developed in response to stakeholders’ and PJM’s observations that there needed to be a more efficient and transparent means to have specific stakeholder questions on specific projects answered in a forum other than belabored discussion at multi-hour stakeholder meetings. The PJM Planning Community gives stakeholders the ability to find answers to their questions by initiating discussions and collaborating with other users - including PJM subject matter experts - about planning initiatives, proposal windows and PJM Transmission Owner Attachment M-3 process questions.

⁴³ *RM21-17*, Initial Comments of American Municipal Power, Inc. (Aug. 17, 2022) (“AMP Initial Comments” or “AMP’s Initial Comments”).

⁴⁴ *Id.* at 19.

⁴⁵ *Id.*

Discussions within the Planning Community are based on planning items discussed in Transmission Expansion Advisory Committee (“TEAC”) stakeholder forums. Through the Planning Community electronic tool, users have the unfettered ability to:

- Research topics quickly and easily, on a 24x7 basis;
- Access a repository of articles or answers to previously submitted user questions;
- View trending topics;
- Initiate discussion board questions which include previously asked questions and answers to popular Planning-related topics, organized by subject matter, and which are facilitated by PJM;⁴⁶
- Interact with other users and PJM subject matter experts within discussion boards, as facilitated by PJM; and
- Submit questions, issues and requests directly to PJM Customer Service in order to “escalate” an inquiry from a discussion thread in the Planning Community to a formal request.

Moreover, internal PJM data shows that since the tool’s creation in 2018, the Planning Community has received 305 questions (otherwise known as “discussion threads”), focusing mainly on consideration of alternate solutions in the context of lower cost. PJM notes that throughout this period, AMP itself initiated 173 of the discussion threads, amounting to 57 percent of all Planning Community activity. Stakeholders from 28 other entities comprised the other 43 percent of the discussion threads. Of the 173 questions posted by AMP, 170 were answered and three (3) of the questions were passed along to the respective transmission owners, who confirmed receipt, but did not provide a response. Overall, 302 out of 305 - over 99 percent – Planning Community discussion threads received responses. It is simply inaccurate to state that

⁴⁶ Examples of discussion boards include Proposal Windows, Stakeholder Meetings and Reliability Planning. A log-in is required to access the PJM Community Planner.

the Planning Community tool is a “deposit of superfluous information on a web portal, without explanation or response to feedback.”⁴⁷ To the contrary, it is clear that stakeholders, including AMP, have made use of the Planning Community and have had a meaningful opportunity to participate in the Attachment M-3 Process. Certainly if AMP had found the tool as useless as it now claims, it would not have made 173 separate inquiries, 99 percent of which received responses.

Second, AMP states “PJM has actually touted the reduction in the number of questions [through the Planning Community tool] as a demonstration that the process is working.”⁴⁸ AMP states that this reduction actually shows that “stakeholders do not have the time and resources to commit questions to writing and post them to the PJM planning tool and wait on a response, rather than simply discuss them during the course of a planning meeting, and reflect[s] stakeholders’ view that the process is futile.”⁴⁹ As an initial matter, PJM notes that every month at each of the three Subregional RTEP meetings, PJM presents open Planning Community questions, thereby enhancing open and transparent engagement between parties. So, AMP and other stakeholders do in fact “have the opportunity to discuss [their questions] during the course of a planning meeting.”⁵⁰

Additionally, the fact that AMP may not have the time or resources to commit questions to writing and post them to the PJM Planning Community tool does not mean that the Transmission

⁴⁷ AMP Initial Comments at 19.

⁴⁸ *Id.* at 20.

⁴⁹ *Id.*

⁵⁰ *Id.*

Owners' Attachment M-3 process is not sufficiently transparent or fails to provide a meaningful opportunity for it or other stakeholders to participate.

Finally, PJM has not heard from any other stakeholder that the Planning Community tool is “futile.” PJM believes that the Planning Community tool is a helpful, efficient way to allow interested stakeholders the opportunity to get answers to their questions, initiate discussions and collaborate with other users, as well as PJM subject matter experts about planning initiatives, proposal windows and PJM Transmission Owner Attachment M-3 questions. If AMP or stakeholders have proposals for how to improve the Planning Community tool, PJM would encourage AMP and others to offer proposed improvements. In the meantime, however, PJM does not believe that the Commission should find, based on the unsupported statements of one stakeholder, that the Planning Community tool is insufficient or that the Transmission Owners' Attachment M-3 process is somehow defective as a result.

B. PJM Provides Clarification Regarding Data Submitted in Support of Other Commenters' Arguments Regarding the Federal Right of First Refusal

In comments,⁵¹ certain parties tout that “despite limited opportunities for competitive transmission development over the last decade, nonincumbent transmission developers have been quite successful in nearly every solicitation that has included a bid from the local incumbent.”⁵² The examples used to support such comments focus primarily on a limited subset of projects, *e.g.*,

⁵¹ *RM21-17*, Initial Comments of NextEra Energy, Inc., at 28 (Aug. 17, 2022) (“NextEra Initial Comments”); *see also RM21-17*, Initial Comments of Anbaric Development Partners, LLC, at 2 (Aug. 17, 2022) (“Anbaric Initial Comments”); LS Power Initial Comments at 106-107; *RM21-17*, Comments by the Electricity Transmission Competition Coalition in Opposition to Certain Aspects of the Proposed Rule, at 3 (Aug. 17, 2022) (“ETCC Initial Comments”) (collectively referred to as “Commenters”).

⁵² NextEra Initial Comments at 28; *see also* ETCC Initial Comments at 3-7 (relying on the 2019 Brattle Report). *See*, J. Pfeifenberger, *et al.*, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value (Prepared for LSP Transmission Holdings, LLC) (Apr. 2019) (the “2019 Brattle Report”), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf.

mostly public policy and multi-value, multi-state projects or unique system needs that provided opportunity for competitive greenfield solutions.⁵³ One example cited for the PJM region is the Artificial Island Project. While that project was a reliability project, it was identified as a unique system stability need stemming from an exceptionally large generating station necessitating an additional transmission outlet. That particular need afforded all proposers (incumbent transmission owners and nonincumbent transmission developers alike) the opportunity to submit a number of innovative proposals, including competitive greenfield solutions.⁵⁴ In the end, LS Power, a nonincumbent transmission developer, was awarded the Artificial Island Project, because its greenfield proposal was found to be the more efficient or cost effective solution.

Another example of a project awarded to a nonincumbent transmission developer through PJM's competitive proposal window includes the Transource 9A Project, which is a multi-state market efficiency project. That project afforded all project proposers an opportunity to propose competitive greenfield solutions. In fact, the project proposal selected as the more efficient or cost effective solution was awarded to a nonincumbent transmission developer.⁵⁵

None of those examples detract from the fact that while nonincumbent developers have had ample opportunity to participate in PJM's 28 competitive proposals windows, of the 464

⁵³ Commenters also referenced the 2022 New Jersey offshore wind competitive proposal window convened at the request of the New Jersey Board of Public Utilities pursuant to PJM's State Agreement Approach process (the "SAA Competitive Proposal Window"). See ETCC Initial Comments at 6. The SAA Competitive Proposal Window identified needs for extending the PJM transmission system where none currently exists. While the results of that solicitation are pending, the New Jersey Board of Public Utilities is expected to announce a project selection in October 2022.

⁵⁴ See LS Power Comments at 104.

⁵⁵ Other project examples cited in comments also appear to be limited to a subset of projects such as large projects addressing New York Independent System Operator's public policy initiatives, Midcontinent Independent System Operator's multi-value solutions, *e.g.*, the Duff-Coleman project and California Independent System Operator's Harry Allen – Eldorado 500 kV transmission line identified to address economically driven needs between Southern California Edison and Nevada Energy.

proposals submitted by nonincumbent transmission developers only 2 percent (three projects) were found to be the more efficient or cost effective solution.⁵⁶ To that point, PJM found that the projects cited by commenters to demonstrate the success of the competitive processes actually support PJM’s finding on what has seemed to work under the competitive process and what has not. More specifically, and as demonstrated by commenters, competition has been effective for a subset of projects focused on public policy⁵⁷ or multi-value/multi-state solutions where there are opportunities for more innovative and competitive greenfield solutions. However, as the PJM data indicated, competition has not been effective for short-term needs that do not warrant or require innovative solutions or provide opportunity for competitive greenfield solutions.⁵⁸

Thus, even when nonincumbent transmission developers have had the opportunity to submit project proposals through PJM’s competitive proposal windows (a total of 42 percent of

⁵⁶ PJM Initial NOPR Comments at 32-50. *See also id.* at 33, Table 2. In arguing that nonincumbent transmission developers have been foreclosed from competitive bidding, Commenters have referred to and relied upon data included in a table drafted by the Brattle Group (“Brattle Table”) and included in the 2019 Brattle Report at 20. *See* Initial Comments of Anbaric Development Partners, LLC at 12-14; NextEra Comments at Attachment A, Figure 3 (the Morris Affidavit at 17-18); and ETCC Comments at 12-13, n.42, 16, n.49. The Brattle Table was used by Commenters to illustrate the point that ISO/RTO qualification and exclusion criteria greatly reduce the scope of projects eligible for competition. PJM found that the Brattle Table indicates that PJM’s competitive process excludes Local Reliability Projects and Projects allocated solely to one zone or upgrades to existing transmission facilities or existing rights of way. That is not correct. There is no blanket local transmission exemption for competition in PJM. By way of clarification, all of PJM’s proposal windows are open to both incumbent transmission and nonincumbent developers. Unless a need is exempted as an immediate-need reliability project, a reliability violation on lower voltage facilities or a thermal reliability violation on substation equipment, all need-related information is posted in PJM’s competitive proposal windows for proposers to submit project proposals, which is how nonincumbent transmission developers were able to submit 464 project proposals in PJM’s 28 competitive proposal windows. It is not until PJM selects the more efficient or cost-effective solution from the proposals submitted through a competitive proposal window that a project is determined to be a Local Reliability Project or a project allocated solely to one zone or an upgrade to an existing transmission facility and, therefore, must be designated to the incumbent transmission owner. As a result, the Brattle Table erroneously overstates for the PJM Region the local transmission exemptions, which, in fact, are much more limited than the chart illustrates.

⁵⁷ *See* LS Power Comments at 106 (citing to the New Jersey offshore wind solicitation where “80 distinct proposals were submitted” by both incumbent transmission owners and nonincumbent transmission developers). The results of that solicitation are pending; however, the New Jersey Board of Public Utilities is expected to announce a project selection in October 2022.

⁵⁸ PJM Initial Comments at 33-46.

proposals submitted by nonincumbent developers overall as compared to the 58 percent of proposals submitted by incumbent transmission owners⁵⁹), in almost all instances the nonincumbent transmission developers' proposals were not found to be the more efficient or cost effective solution (even with a cost containment provision).

Moreover, given the significant amount of proposals submitted by nonincumbent transmission developers for mostly short-term needs, the process has required an extensive amount of time and effort on the part of PJM,⁶⁰ PJM transmission owners, and nonincumbent transmission developers resulting in only three out of 185 projects awarded to nonincumbent transmission developers. More specifically, based on a review of hours dedicated to the PJM competitive proposal windows, PJM found that PJM staff logged approximately 49,354 hours.⁶¹

C. PJM Provides Clarification Regarding a Recent Rate Schedule for Reliability Must-Run Service

NARUC supports the NOPR proposal to require transmission providers to use “best available data” for the development of Long-Term Scenarios,⁶² and emphasizes its belief that “using reasonable data inputs is essential to effective Long-Term Regional Transmission Planning.”⁶³ In support of this position, NARUC points to a Reliability Must-Run (“RMR”) rate schedule recently filed by NRG Power Marketing LLC, on behalf of Indian River Power LLC

⁵⁹ *But cf.*, NextEra Comments, Attachment A (Morris Affidavit), at 15, n.52, which incorrectly states that “[t]hrough its competitive solicitation window, PJM awarded 136 projects to incumbent [transmission owners]. Few of these were open to non-incumbents because virtually all of them involved upgrades to existing facilities. Because it is unknown which were open to non-incumbents, none of the 136 are included in this list of 25 competitive solicitations” (citations omitted).

⁶⁰ PJM Initial Comments at 47.

⁶¹ Those numbers generally refer to the PJM system planning division and do not include other support groups, such as legal.

⁶² NOPR at P 130.

⁶³ NARUC Comments at 12.

(“Indian River”).⁶⁴ In its comments, NARUC seems to suggest that PJM should have anticipated that the Indian River Unit 4 would deactivate because it had been “uneconomic for years,” and PJM therefore should have proactively accelerated the transmission upgrades that would be needed to address any reliability violations resulting from the then-hypothetical deactivation of Indian River Unit 4.⁶⁵

PJM agrees with NARUC that it is important for transmission providers to use best available data when developing Long-Term Scenarios.⁶⁶ That said, PJM wishes to clarify that under its currently-effective Tariff rules, PJM does not have a process pursuant to which it could have identified a need for transmission enhancements or expansions to address the *potential* retirement of Indian River Unit 4 (or of any generating unit). Rather, PJM’s Tariff provides for the identification of transmission system upgrades to mitigate identified reliability violations associated with a *planned* generator deactivation.⁶⁷ Only *after* a generator owner gives PJM notice of the planned deactivation does PJM have the authority to perform a study of the transmission system to determine whether the planned deactivation would adversely affect system reliability and, if so, what transmission upgrades would be needed to resolve the identified needs.⁶⁸

⁶⁴ NARUC Comments at 14. *See also* NRG Power Marketing LLC, Tariff Filing of NRG Power Marketing LLC, Docket No. ER22-1539-000, at 14 (Apr. 1, 2022).

⁶⁵ NARUC Comments at 14-15 (“Given the age of the transmission facilities, much of the identified upgrades may have been needed soon in any event. The purported need for the RMR is lamentable for various reasons, including that the plant has been uneconomic for years, its significant air emissions are inconsistent with numerous state policies, and its continued use may impose additional costs upon ratepayers of up to several hundred million dollars over the life of the RMR. Better data input in long-term planning may have resulted in accelerated work on necessary transmission upgrades, thus obviating the need for consideration of an RMR. Both the generator retirement date and the aging transmission system upgrade date appear to be data inputs that could be considered in Long-Term Regional Transmission Planning”).

⁶⁶ PJM Initial Comments at 76-77.

⁶⁷ *See* PJM Tariff, Part V, § 113.

⁶⁸ *See* PJM Tariff, Part V, § 113.1. Under the Tariff rules that were in effect when Indian River notified PJM that it intended to retire Indian River Unit 4, a generator owner was required to give PJM 90 days’ notice of its intent to deactivate its generating unit, after which PJM had 30 days to perform necessary reliability analyses to assess whether

Thus, as far as the Indian River Unit 4 deactivation is concerned, PJM complied with its Tariff when it: (i) performed reliability analyses in response to Indian River's June 29, 2021 notice that it intended to retire Indian River Unit 4, effective May 31, 2022, due to expected uneconomic operations; (ii) identified reliability violations resulting from the planned deactivation and the estimated time it would take to complete the necessary system upgrades to alleviate the reliability impacts; and (iii) upon receipt of Indian River's agreement to operate beyond its planned deactivation date, notified Indian River that it was entitled to pursue either a cost of service recovery rate⁶⁹ or receive the Deactivation Avoidable Cost Credit⁷⁰ provided for under the Tariff.

PJM does not have a specific criteria by which to identify enhancements or expansions to address potential retirements.⁷¹ Moreover, the issue is not as simple as NARUC suggests. For instance:

- Generation resource owners own interconnection rights and could have entered the PJM new services queue to install a replacement generator at the site, avoiding the need for reinforcements; and

the planned deactivation would adversely affect the reliability of the PJM Transmission System absent upgrades to the system. PJM recently submitted a filing proposing to revise the timing and process by which it will study generator deactivation notices; the Commission accepted the revised Tariff provisions to be effective as of September 11, 2022. *See PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER22-2342-000 (Aug. 19, 2022). Under both the rules in effect when Indian River notified PJM of its intent to deactivate Indian River Unit 4 and the currently-effective rules, if PJM identifies reliability criteria violations associated with a planned deactivation, PJM identifies the transmission upgrades that would be needed to resolve the identified issues. If the transmission upgrades cannot be put in place prior to the requested deactivation date, then PJM may request that the generator stay online beyond its proposed deactivation date in order to maintain system reliability pending the completion of necessary transmission system upgrades. Should a generation owner elect to continue to operate a generation unit beyond its planned deactivation date in order to maintain system reliability pending the completion of necessary transmission system upgrades, the generation owner can elect to either (i) pursue a cost of service recovery rate or (ii) receive the Deactivation Avoidable Cost Credit (as defined in Part V of the PJM Tariff). *See PJM Tariff*, Part V, § 113. The generation owner is not obligated to operate beyond its requested deactivation date.

⁶⁹ PJM Tariff, Part V, § 119.

⁷⁰ PJM Tariff, Part V, § 114.

⁷¹ Without such criteria does not have the authority to pursue costly enhancement or expansions, particularly given the fact that such enhancements or expansions may not be needed if the generator were to have decided to refurbish the existing generator or enter the PJM interconnection queue and build a replacement generator at the site.

- The same “market signals” that NARUC suggests that PJM should have seen to know that the deactivation of Indian River Unit 4 was impending were also there for all market participants. Other interconnection customers could have entered the new services queue to avoid the need. A transmission upgrade is a backstop, not the primary desired fix of replacement generation.

PJM does not raise these issues to say that analyses of at-risk generation should not be undertaken.

PJM agrees that they should be studied and analyzed. However, PJM raises these complexities as the criticism raised by NARUC concerning Indian River Unit 4 facility is not so black and white.

Notwithstanding the above, as stated in its Initial NOPR Comments, PJM agrees that it is appropriate to consider resource retirements when developing planning assumptions for its regional transmission planning process,⁷² and supports engaging in economic impact analyses of generation resource retirements or deactivations in a transparent manner.⁷³ As PJM cautioned, however, developing generation retirement forecasts may be interpreted by stakeholders within the PJM footprint as sending economic signals to the viability of existing generating units, which can have a number of consequences.⁷⁴ As such, PJM urges the Commission to provide clear direction on how to balance the heightened transparency and public processes proposed in the NOPR with the need to have appropriate safeguards against releasing data and results that could preempt unit owner economic decisions, as well as decisions by market participants.

⁷² NOPR at P 104 & n.193.

⁷³ See PJM Initial NOPR Comments at 69.

⁷⁴ See *id.* (“Nevertheless, the Commission must recognize that publicly releasing information as to specific generators at risk of retirement, and then building new transmission based on that prognostication, has direct market as well as plant workforce impacts. Such public releases could drive disinvestment in generation units to the extent that transmission is built to move generation as if the plant were no longer operational. Moreover, the impact on the workforce of a generating plant cannot be ignored as laborers seek to square the transmission planner’s analysis with management’s pronouncements and the terms of labor agreements. Further, once the transmission case is released, this information will be apparent so there is no practical way to mask the specific generation units that the transmission planner has deemed to be shut down by a specific date”).

D. Clarification Regarding Evidence Offered in Support of Portfolio-Based Transmission Planning

New Jersey Board of Public Utilities (“NJ BPU”) urges the Commission to exercise its authority under FPA section 206 “to mandate long-term multi-value, portfolio-based transmission planning in order to remedy currently unjust and unreasonable practices affecting electricity rates.”⁷⁵ NJ BPU offers evidence to demonstrate “that the failure to exercise this authority will likely cost consumers tens of billions of dollars in needlessly high electricity costs over the coming years.”⁷⁶ With respect to the PJM Region, NJ BPU points to PJM’s recently-issued Offshore Wind Transmission Study: Phase 1 report⁷⁷ to support its argument that “proactive, portfolio-based planning in PJM could ultimately save ratepayers over \$30 billion compared to the status quo.”⁷⁸ Although PJM agrees with NJ BPU that there is value in portfolio-based transmission planning, the cost savings estimates upon which NJ BPU relies to support its argument are incorrect, at least with respect to PJM. Accordingly, PJM provides the following information to correct the record in this proceeding.

⁷⁵ *RM21-17*, Comments of New Jersey Board of Public Utilities, at 9 (Aug. 17, 2022) (“NJ BPU Initial Comments”).

⁷⁶ *Id.* at 9.

⁷⁷ *See id.* at 6, citing PJM Interconnection, L.L.C., Offshore Wind Transmission Study: Phase 1 Results (Oct. 19, 2021), available at: <https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx> (“OSW Transmission Study”). The OSW Transmission Study was a collaborative effort between PJM and its States, and is purely advisory in nature. PJM conducted a PJM-wide reliability study to determine reinforcements to the onshore grid to reliably deliver the 14,268 MW of announced offshore wind in the PJM region, as well as to achieve all state Renewable Portfolio Standards (“RPS”) targets in the PJM region by determining the necessary renewable capacity by resource type and location. OSW Transmission Study at 1. As PJM explained, “[b]y synchronizing the planning of its coastal states’ offshore wind deployment, PJM is able to identify transmission solutions that could present a more efficient and economic path for states to achieve their offshore wind policy objectives than if each state integrated their offshore wind generation completely independent of one another.” *Id.* PJM analyzed offshore wind injection totals that ranged from 6,416 MW to 17,016 MW, in addition to modeling all state RPS targets, across short-term and long-term scenarios. For the five scenarios, the cost estimates to upgrade the existing onshore transmission system were identified to be \$627.34 million in the short-term scenario and between \$2.16 billion and \$3.21 billion for the long-term scenarios. *Id.*

⁷⁸ NJ BPU Initial Comments at 7.

NJ BPU correctly relies on information contained in the OSW Transmission Study to support its argument that “if [PJM] planned upgrades as a holistic portfolio, it could build all the necessary onshore network upgrades to support *all* of PJM states’ current offshore wind *and* total RPS goals for just \$3.2 billion.”⁷⁹ However, NJ BPU points to two additional reports⁸⁰ and states that “an analysis of PJM interconnection queue data indicates that it would cost \$6.4 billion just to build the onshore network upgrades for 15.6 GW of offshore wind, if they were to be built piecemeal through the interconnection queue process—or about \$413 per kW of interconnected capacity.”⁸¹ NJ BPU concludes that, assuming the \$413 per kW costs are the same for other resource types, “it follows that interconnecting the aforementioned 87.1 GW of capacity through piecemeal interconnection queue projects would cost nearly \$36 billion in total—*more than eleven times* the \$3.2 billion cost of the integrated portfolio approach.”⁸² NJ BPU’s assumption that the average per-unit network upgrade costs for all resource types is \$413 per kW is incorrect.

Based on PJM’s internal analyses, the analysis upon which the NJ BPU relies overstates transmission costs associated with the interconnection of new renewable generation in PJM by orders of magnitude. The \$413 per kW estimate was derived from a limited number (24) of interconnection studies for offshore wind capacity. The transmission costs necessary to support offshore wind capacity are not indicative of the costs for other renewable types given their massive

⁷⁹ NJ BPU Initial Comments at 6 (emphasis original). NJ BPU states that this would amount to 87.1 GW of capacity altogether. *Id.*

⁸⁰ NJ BPU cites the following reports: (i) Brattle Grp. & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf; reprinted in Comments of Americans for a Clean Energy Grid, App. A (Oct. 12, 2021) (“Brattle/Grid Strategies Study”) and (ii) Brandon W. Burke, Michael Goggin, & Rob Gramlich, Offshore Wind Transmission White Paper 14 (2020), <https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf>.

⁸¹ NJ BPU Initial Comments at 6.

⁸² NJ BPU Initial Comments at 7 (emphasis original).

size per each site. For example, nearly two-thirds of the transmission costs for these 24 interconnection studies were driven by three injection locations. Often, developers submit interconnection requests that are exploratory in nature, and result in much higher transmission costs in the interconnection study phase than the actual transmission costs for the ultimate interconnection projects that move forward to commercial operation. In other words, the interconnection network upgrade requirements and costs for the identified interconnection studies for offshore wind capacity are expected to overall be much lower on a per kW basis by the time the developers execute Interconnection Service Agreements.

In short, while PJM agrees that proactive, portfolio-based planning in PJM would likely result in savings to ratepayers, PJM finds NJ BPU's estimated cost savings associated with such an approach to be overstated with respect to the PJM Region. PJM raises this issue lest the record contain and the Commission rely on numbers that do not accurately represent the entire cost picture.

III. PJM'S RESPONSE TO CERTAIN PROPOSALS IN OTHER PARTIES' COMMENTS

A. PJM Proposes an Alternative to Other Parties' Proposals to Allow States to Opt In or Out of the Federal Right of First Refusal

On the issue of the federal right of first refusal, some commenters argue that the Commission should, as an alternative, "hard-wire" into the federal tariff specific state opt-in or opt-out provisions.⁸³ As a practical matter, there is no need for the Commission to reach this proposal. Instead, PJM proposes below an alternative approach – grounded in today's planning practices – that respects and gives full effect to both state and federal authority in this area.

⁸³ See e.g., MISO Initial Comments at 21; Harvard Initial Comments at 5-6, 31-33.

Moreover, as explained below, there are unaddressed legal and practical questions as to how proposals for a “hard-wired” opt-in or opt-out would work in practice that the Commission must address if it were to pursue this approach.

The proponents of state opt-in or opt-out proposals inadvertently conflate the difference between states exercising their authority over siting and certification/franchising of public utilities under state laws and the Commission exercising its authority over Planning Authorities under federal law and through a federal tariff. The two are not compatible given their separate origins. Moreover, mixing the two only works to blur those lines.

Planning Authorities *already* take into account the impact of state siting and certification/franchising laws when deciding which project to select in carrying out their federal tariff responsibilities. One of the key components of deciding which project to select through an Order No. 1000 competitive solicitation is the feasibility of siting the facility under state law.⁸⁴ Moreover, state limitations on which entity may qualify as a public utility for purposes of state siting and certification are decided by state legislatures and embodied in laws passed by those legislatures. As a result, they are not subject to potential project-by-project application or changes to those laws based solely on changing Governors or the make-up of state public utility commissions. In essence, the states are already exercising their policy judgments over the right of first refusal through their state siting and certification laws, and Planning Authorities are taking those into account when examining the feasibility of siting a project proposed by a nonincumbent versus one proposed by an incumbent. As a result, there is no need for the Commission to go

⁸⁴ For example, in determining the feasibility of siting, PJM has retained state counsel to advise it on the application of state siting and certification laws where questions would otherwise exist.

further and “hard-wire” into a federal tariff a particular opt-in or opt-out in order to fully respect and make actionable state authority in this area.

By contrast, adding a specific opt-in or opt-out provision into the federal tariff will create its own set of legal ambiguities and practical issues. For one, the Commission would have to define how often a state may exercise its opt-in or opt-out right. Can a state opt in or opt out selectively on a project by project basis? Unlike state siting and certification laws that are based on state legislative action, who in the state decides whether the state may opt in or opt out of the federal tariff? Is it the state public utility commission or is it another state authority that has jurisdiction over siting? Does it require a formal action of that body and can that body simply revoke that action upon a change of administration at the state level? And, if a state opts out of the federal tariff, what process does the Planning Authority then use to select the more efficient or cost-effective solution in that state for a need that crosses state lines? Finally, if part of the project were to fall into a National Interest Electric Transmission Corridor and other parts of the line do not fit within that Corridor in a given state, what is the impact of that action on the Planning Authority’s choosing a project that would span both areas designated Corridors and areas not so designated?

None of these difficult issues would need to be addressed if the Commission were to simply recognize in its Final Rule that Planning Authorities are to continue, as they do today as a practical matter, consider state siting and certification laws and the feasibility of siting a given project in their project designations. Such an indication would avoid the complications and additional detail

that would be needed were the Commission to add to the Planning Authorities' federal tariffs a provision allowing a state to state opt-in or opt-out of competition.⁸⁵

Finally, PJM notes certain practical issues that would arise were the Commission to “hard-wire” in an opt-in or opt-out provision rather than simply recognizing the plenary authority of states to site facilities as described above. By way of example, assume, as is the case in PJM and many other jurisdictions, that a single transmission zone spans multiple states. The Planning Authority has chosen a single transmission line, which spans at least two states within that zone (and potentially additional zones) to address an identified regional need. “State A” within that zone is comfortable with the Planning Authority’s competitive process of choosing the more efficient or cost-effective project as between incumbent transmission owners and nonincumbent transmission developers, and therefore does not exercise any opt-in or opt-out rights. “State B,” on the other hand, indicates that for its portion of the line, it is exercising its opt-out right (or never exercised its right to opt in to that portion of the federal tariff) and insists the line be built by the incumbent transmission owner.

In this instance, the Planning Authority, if it awarded the project in State A to a nonincumbent, would have to establish a specific demarcation point and build associated substation infrastructure in order that the “hand-off” at the state border from the nonincumbent transmission developer to the incumbent transmission owner were clear. This would clearly add to customer cost and cause the construction of additional, otherwise unnecessary infrastructure to be sited at the state border solely to establish that new demarcation point as between the incumbent

⁸⁵ PJM is mindful of the fact that the Commission implemented a state opt-out for end user participation in RTO Demand Response markets. However, that was a notably different fact situation as the Commission did not have plenary jurisdiction over end users. By contrast, authority over transmission development and siting spans both federal and state jurisdiction.

transmission owner's facility and the nonincumbent transmission developer's facility. Moreover, complex maintenance and operational protocols would be needed as responsibilities to operate and maintain this single line are now divided between two entities.

PJM recognizes that such "hand-offs" already exist among utilities at the borders of their zones today. However, as a practical matter, "hard-wiring" in a state opt-in or opt-out would require additional costly "hand-off" infrastructure, potentially within a single zone. In addition, unlike today where these hand-offs are arranged between two incumbent utilities with fixed zonal boundaries, these new hand-offs (and associated infrastructure and maintenance and operating agreements) would now have to be negotiated at the front end between competitors to an Order No. 1000 competitive solicitation. Although not impossible, the heightened level of disputes and future challenges surrounding maintenance and operation of what is, in effect, a single line will be inevitable.

PJM poses these issues *not* to take sides on the degree of state authority over the transmission development process. Rather, PJM explains above that both state and federal authority can be harmonized and respected, if the Commission were to simply make clear in its Final Rule that state siting and certification laws must be (as they are today) considered by the Planning Authority in exercising its planning function. This approach would avoid all of the complications outlined above with the alternative proposal of "hard-wiring" into the federal tariff complex opt-in and opt-out procedures.

B. PJM Supports Consideration of Alternatives to the NOPR's Proposal to Require Transmission Providers to Identify Geographic Zones

For the reasons set forth in its Initial Comments, PJM does not support the Commission's proposal to require transmission providers to identify geographic zones with the potential for large amounts of new generation, nor does PJM believe that transmission providers should be

responsible for assessing whether there is evidence that generation developers have demonstrated commercial interest in developing generation within a geographic zone.⁸⁶ That said, PJM believes there is value in approaches that would be more tailored to specific marketplace information and the nearer term decisions of interconnection customers. To that end, PJM proposed an alternative process pursuant to which PJM would: (i) assess whether clusters of generation interconnection requests could drive more robust transmission solutions to interconnect greater numbers of generation resources at once, and (ii) present this information to states which could, under PJM's State Agreement Approach process,⁸⁷ approve a more robust build (and arrive at a cost-sharing arrangement as between interconnection customers and the state(s)).⁸⁸ PJM also discussed additional initiatives already in place pursuant to which PJM could assess potential geographic clusters to identify infrastructure that may be necessary to plan for transmission needs of an anticipated future generation to meet a changing resource mix and demand.⁸⁹

In their initial comments, both NJ BPU and Vistra Corp. ("Vistra") propose additional alternatives to the Commission's geographic zone proposal that build on the original concept that PJM described above and in its Initial Comments. Specifically, NJ BPU proposes a generator subscription model, pursuant to which transmission projects would be built only if generators subscribed to a sufficient percentage of the transmission capacity and committed to paying the corresponding costs.⁹⁰ Under NJ BPU's proposal, states interested in incentivizing transmission development within certain geographic zones could also voluntarily subscribe to a portion of such

⁸⁶ See PJM Initial Comments, Section III.A.2.e.

⁸⁷ See Operating Agreement, Schedule 6, section 1.5.9.

⁸⁸ See PJM Initial Comments, Section III.A.2.e.

⁸⁹ See *id.*

⁹⁰ *Id.* at 16.

a transmission project's capacity and commit load in their states to paying for the relevant costs.⁹¹ NJ BPU further recommends that transmission providers be encouraged to explore mechanisms that could enable the transfer of such capacity subscriptions from states or generators.⁹²

On the other hand, Vistra argues that rather than relying on transmission providers' projections of which geographic zones may have the potential for large amounts of new generation, the Commission should "provide for use of open seasons or other comparable tools to elicit concrete commitments from generator developers, ideally using a structure where developers put 'skin in the game' in exchange for rights to newly created interconnection capacity."⁹³

Specifically, Vistra proposes a two-step process whereby the transmission provider would: (i) identify zones requiring new transmission capacity to support new resource development and invite generation developers to submit valid commercial expressions of interest in the increased transmission capacity, and (ii) institute a commercial open season process pursuant to which all or a portion of the rights to new transmission capacity would be allocated via an open, nondiscriminatory process, whereby the customer acquiring such rights would be obligated to pay for its relative share of the upgrade costs (via an offer into the open season) and separately to allow for third-party use of capacity deliverability rights that they hold, but are not currently using.⁹⁴

PJM believes that, subject to certain refinements, the proposals offered by NJ BPU and Vistra may have merit and are worthy of further dialogue among PJM, its stakeholders, and the Commission. For instance, rather having generators "subscribe" to a portion of a transmission

⁹¹ *Id.* at 17.

⁹² *Id.*

⁹³ *RM21-17*, Initial Comments of Vistra Energy Corp., at 2 (Aug. 17, 2022) ("Vistra Initial NOPR Comments").

⁹⁴ *Id.* at 25-26.

project's capacity as suggested by NJ BPU, Vistra's proposal to invite generation developers to submit valid commercial expressions of interest in increased transmission capacity in a particular area would help the transmission provider to identify transmission solutions to interconnect greater numbers of generation resources at once. Consistent with the Commission's goals set forth in the NOPR, such a process could result in a more holistic approach to building transmission enhancements or expansions to accommodate multiple interconnection requests, rather than network upgrades to address single interconnection requests. In turn, this process could allow associated costs to be spread among a larger group of interconnection customers. Such a process could benefit both the system and the ability to interconnect greater amounts of renewable resources.

While PJM continues to oppose the geographic zone proposal for the reasons set forth in its Initial Comments,⁹⁵ PJM believes alternate processes may accomplish the Commission's goal of finding more efficient and cost-effective transmission solutions. PJM requests that it be permitted to work with its stakeholders to determine a more case-specific flexible approach that builds on and is better synchronized with the interconnection process and market developments, and accommodates topologies as diverse as those in PJM versus those in far less densely networked regions of the nation.

C. PJM Provides the Following Comments Regarding Cost Allocation Methodologies for Facilities Selected through Long-Term Regional Transmission Planning Process

Several commenters urge that states must have the final decision regarding cost allocation. For instance, the Organization of PJM States, Inc. ("OPSI") argues that if retail regulators reach

⁹⁵ PJM Initial NOPR Comments at III.A.2.e.

an agreement regarding cost allocation, the transmission provider “should be required to file it for consideration under [section] 205 of the FPA.”⁹⁶ OPSI states that if a transmission provider prefers a different cost allocation methodology from that agreed to by state regulators, then the transmission provider “may also make a filing proposing its preferred alternative, while also presenting the method agreed to by the relevant state entities.”⁹⁷ Similarly, NARUC recommends that “if the states in which a selected regional transmission facility will be located unanimously agree on a state-negotiated alternate cost allocation method,” that the transmission provider should be required to file that cost allocation methodology with the Commission.⁹⁸ NJ BPU likewise argues that “in the event that the transmission provider disagrees with the approach desired by states, . . . the Commission require[s] [the transmission provider] to submit the states’ approach as well as their own in their Section 205 filing,” leaving it to the Commission to decide which tariff filing to accept.⁹⁹

As PJM explained in its Initial Comments,¹⁰⁰ the PJM transmission owners have exclusive authority and responsibility to submit filings under FPA section 205 “in or relating to . . . the transmission rate design under the PJM Tariff.”¹⁰¹ Therefore, as PJM explained, even though PJM agrees that providing state regulators with a formal opportunity to work with the PJM transmission owners to develop a cost allocation method for facilities selected through Long-Term Regional Transmission Planning process will increase stakeholder and affected state authorities’ support for

⁹⁶ OPSI Initial Comments at 10.

⁹⁷ *Id.*

⁹⁸ NARUC Comments at 53.

⁹⁹ NJ BPU Comments at 17-18.

¹⁰⁰ *See* PJM Initial NOPR Comments, Section III.C.1.

¹⁰¹ CTOA § 7.3.1. *See also* PPL Elec. Utils. Corp., 177 FERC ¶ 61,123, at PP 34-37 (2021) (affirming the scope of the PJM Transmission Owners’ FPA section 205 filing rights under the Tariff and CTOA).

those facilities and that, in turn, the likelihood those facilities will be sited and ultimately developed,¹⁰² such opportunities must be harmonized with the transmission owners' filing rights set forth in the CTOA and Tariff provisions.¹⁰³ PJM therefore requested that the Commission clarify the interrelationship of the proposals set forth in the NOPR with the PJM Region's present allocation of rights to revise existing or propose new *ex ante* cost allocation methods, which is embodied in the *Atlantic City v. FERC* decision.¹⁰⁴ PJM further requests that the Commission keep these principles in mind as it considers the state regulators' comments described above.

Additionally, PJM noted the importance of allowing transmission providers to be permitted to use existing *ex ante* cost allocation methodologies as the default cost allocation methodology to apply to facilities selected through the Long-Term Regional Transmission Planning process (absent agreement by all affected states regarding an alternate methodology as discussed below). Absent unanimous agreement by all states potentially impacted by an alternate cost allocation methodology, PJM continues to believe that the existing *ex ante* allocation methodology must apply to the facilities selected through the Long-Term Regional Transmission Planning process. In lieu of an agreed-upon alternate cost allocation methodology, PJM believes that the applicable

¹⁰² NOPR at P 299.

¹⁰³ See PJM Initial NOPR Comments, Section III.C.1.

¹⁰⁴ See *Pennsylvania-New Jersey-Maryland Interconnection*, 105 FERC ¶ 61,294 (2003), *order on reh'g*, 108 FERC ¶ 61,032 (2004) (approving Settlement Agreement). The provisions of the Settlement Agreement were memorialized in Tariff, section 9.1(a) which provides: "The Transmission Owners shall have the exclusive and unilateral rights to file pursuant to Section 205 of the [FPA] and the [Commission's] rules and regulations thereunder for any changes in or relating to the establishment and recovery of the Transmission Owners' transmission revenue requirements or the transmission rate design under the PJM Tariff, and such filing rights shall also encompass any provisions of the PJM Tariff governing the recovery of transmission-related costs incurred by the Transmission Owners." Tariff, section 9.1(d) further specifies that the PJM Transmission Owners' unilateral filing rights include any changes to Tariff, Schedule 12, which sets forth the methodologies for allocating costs of transmission enhancements and expansions included in PJM's RTEP). See *Atlantic City Elec. Co. v. F.E.R.C.*, 295 F.3d 1 (D.C. Cir. 2002), *order on remand*, *Pennsylvania-New Jersey-Maryland Interconnection*, 101 FERC ¶ 61,318 (2002), *subsequent appeal*, 329 F.3d 856 (D.C. Cir. 2003).

tariffed *ex ante* cost allocation method should be used to assign cost responsibility for the facility so as to ensure that gridlock in reaching consensus on alternative cost allocations does not stymie the development of needed transmission.¹⁰⁵ It is especially appropriate to utilize the existing cost allocation methodologies as a default as the states participated in the development of such methodologies, particularly the reliability and State Agreement Approach cost allocation methodologies, both of which were litigated with support from the states for the final method filed.¹⁰⁶

D. PJM Requests that the Commission Clarify the Authority Over and Process to Select Projects through the Long-Term Regional Transmission Planning Process

In its comments, ISO-NE requests that the Commission give states a greater role “in all aspects of policy-based transmission planning – not just the criteria for selecting and methodology for allocating costs of long-term transmission facilities.”¹⁰⁷ Specifically, ISO-NE urges the Commission to give states in the ISO-NE region a central decision-making role throughout the policy-based planning process, with the ISO conducting the necessary studies and playing a technical supporting role throughout the process.¹⁰⁸

PJM requested that the Commission make several clarifications regarding the NOPR’s proposed selection process for regional transmission facilities identified through the Long-Term Regional Transmission Planning process.¹⁰⁹ In particular, PJM requested that the Commission make clear that although consultation with the states and stakeholders is a key part of the proposed

¹⁰⁵ See PJM Initial NOPR Comments, Section III.C.1. See also NOPR at P 320.

¹⁰⁶ See PJM Initial NOPR Comments, Section III.C.1.

¹⁰⁷ ISO-NE Initial Comments at 16.

¹⁰⁸ *Id.* at 17-18.

¹⁰⁹ See PJM Initial NOPR Comments, Section III.B.3.

Long-Term Regional Transmission Planning process (and already is addressed through Order Nos. 890 and 1000 for the near-term planning processes), at the end of the day, the transmission planner must remain the entity responsible and accountable for selecting the more efficient or cost-effective project consistent with the criteria set forth by the Commission in Order Nos. 890, 1000 and any Final Rule coming out of this proceeding.

While PJM supports providing additional opportunity for involvement by states and the broader stakeholder membership in the Long-Term Regional Transmission Planning process, particularly as states and stakeholders take a more active role in helping to shape the long-term transmission needs driven by changes in the resource mix and demand, the transmission provider should retain authority to select project(s) based on a defined process, serving its role as the registered Transmission Planner, which is much more than a “technical supporting role.” Accordingly, to the extent the Commission is inclined to allow for regional flexibility regarding the level of involvement by states in the Long-Term Regional Transmission Planning process, PJM respectfully requests that the Commission make clear that it is not requiring that states in each region be given a central decision-making role over facilities selected through the Long-Term Regional Transmission Planning process.

ISO-NE further suggests that the NOPR’s proposed project selection criteria is ambiguous, and requests that the Commission clarify that the transmission provider “is not required to identify transmission facilities to address system issues identified in each scenario run, but rather a set of ‘least regrets’ transmission facilities that address common issues identified across multiple scenarios.”¹¹⁰ PJM agrees that the NOPR is unclear and supports the request for the Commission

¹¹⁰ ISO-NE Initial NOPR Comments at 21.

to provide clarity regarding the ISO-NE “least regrets” approach.¹¹¹ Additionally, PJM requests the Commission provide further clarity that transmission providers can identify trends across multiple three-year Long-Term Regional Transmission Planning process planning cycles without necessarily identifying specific transmission facility reinforcements. Then, if trends reveal a system need, then PJM should be permitted the flexibility to continue to pursue solutions under window solicitations.

E. PJM Agrees with Commenters Who Argue that Requiring Transmission Providers to Consider Corporate Commitments in Developing Scenarios for the Long-Term Regional Transmission Planning Process Could Create Compliance Risks

In the NOPR, the Commission proposes that transmission providers be required to incorporate seven categories of Factors into the development of Long-Term Scenarios.¹¹² As indicated in its Initial NOPR Comments, PJM generally supports the specific categories of Factors, but suggested several modifications to the Commission’s list of Factors.¹¹³ After reviewing the comments filed by other parties in this docket, PJM offers an additional modification to the Commission’s list.

In particular, a number of commenters cautioned that the Commission’s proposal to include “corporate commitments ... that affect the future resource mix and demand”¹¹⁴ is vague and could lead to compliance risk.¹¹⁵ PJM agrees. Specifically, PJM believes that requiring transmission providers to locate and catalogue all possible corporate goals or commitments in regional, long-

¹¹¹ See PJM Initial NOPR Comments, Section III.B.3.

¹¹² See NOPR at P 104.

¹¹³ See PJM Initial NOPR Comments at 64-69.

¹¹⁴ See NOPR at P 104.

¹¹⁵ See, e.g., MISO Initial Comments at 36-37; ISO-NE Initial Comments at 26-27; *RM21-17*, Comments of the Illinois Commerce Commission, at 7 (Aug. 17, 2022).

range transmission planning would create an unreasonable compliance obligation, as well as a resource drain. It is not practical or efficient for PJM to be expected to research, track and maintain data about the commitments and goals of corporations located in the expansive PJM footprint. Although PJM supports a process by which transmission providers could develop a record of corporate commitment and goals through surveys and other means, PJM is nonetheless concerned that it would likely have incomplete information about the corporate commitments and goals of the corporations within the PJM Region, and that a compliance requirement to identify all corporate goals, whether identified to the transmission provider or not, would be an inappropriate and unworkable overreach.

Accordingly, PJM respectfully requests that the Commission consider an approach similar to the approach recommended by PJM for considering any local laws, local regulations and/or local goals as factors for developing Long-Term Scenarios. Specifically, PJM recommended that the Commission only require transmission planners to consider local laws, local regulations and/or local goals to the extent they are explicitly brought to PJM's attention by states, stakeholders, or other local regulators.¹¹⁶ That is, PJM requested that the Commission clarify that the burden to ensure that a transmission planner is aware of any local laws, local regulations and/or local goals that should be considered is on states, stakeholders, or other local regulators, not on the transmission planner.¹¹⁷ Similarly, PJM believes that the burden to ensure that a transmission planner is aware of corporate commitments and goals to include as Factors for the development of Long-Term Scenarios should be on the corporation or any other entity that believes such commitment or goal should be considered.

¹¹⁶ See *PJM Initial NOPR Comments* at 68.

¹¹⁷ *Id.*

F. PJM Believes the Commission Should Reject the NOPR’s Proposal to Entwine Interconnection Planning and Regional Transmission Planning

In the NOPR, the Commission proposed to require transmission providers to consider, as part of the Long-Term Regional Transmission Planning process, regional transmission facilities that would address interconnection-related needs previously identified in the generator interconnection process in specified circumstances.¹¹⁸ PJM and other commenters urged the Commission to decline to implement the Network Upgrade Proposal, explaining that the proposal invites gaming, creates perverse incentives for generation developers, and would result in undue discrimination.¹¹⁹

In its comments, Enel North America, Inc. (“Enel”) supports the Network Upgrade Proposal as “recogniz[ing] that network upgrades are ultimately part of integrated transmission systems, and provide at least some benefit to all system users,” but argues that the proposal “risks delaying necessary upgrades relative to what could be achieved via more proactive planning.”¹²⁰ Enel references the Working Paper that it attached to its comments in response to the Advance Notice of Proposed Rulemaking¹²¹ in this docket,¹²² and maintains that its proposal improves

¹¹⁸ Specifically, the NOPR proposes to require transmission providers to consider proposed transmission facilities in the regional planning process if those facilities would address interconnection-related needs that: (i) have been identified in at least two queue cycles in the past five years; (ii) require an upgrade of at least 200 kV or have an estimated cost of at least \$30 million; (iii) have not been developed due to request withdrawals; and (iv) are not slated for address by an upgrade in an executed agreement (or in an agreement the developer requested to be filed unexecuted). PJM refers to this proposal herein as the “Network Upgrade Proposal.”

¹¹⁹ See, e.g., PJM Initial NOPR Comments at 87-92; EEI Initial Comments at 18; CAISO Initial Comments at 33-35.

¹²⁰ *RM21-17*, Comments of Enel North America, Inc. on Notice of Proposed Rulemaking (Aug. 17, 2022) (“Enel NOPR Comments”).

¹²¹ *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advance Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021) (“ANOPR”).

¹²² *RM21-17*, Comments of Enel North America, Inc. (Oct. 12, 2021) (“Enel ANOPR Comments”). See also *id.*, Attachment, Enel Green Power, Working Paper, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, at 5 (“Enel Working Paper”).

transmission planning by integrating the generator interconnection process.¹²³

As PJM stated when Enel previously submitted its Working Paper, PJM has concerns about specific aspects of the proposals set forth therein. As such, and for the reasons more fully described in PJM's ANOPR Reply Comments,¹²⁴ PJM cautions the Commission against incorporating the proposals in the Enel Working Paper in any Final Rule without allowing the opportunity for further discussion on the issues presented therein.

G. PJM Provides the Following Comments on Parties' Requests that the Commission Require the Establishment of an Independent Transmission Monitor

In the ANOPR, the Commission sought comments on whether it would be appropriate to establish an independent entity to monitor the planning and cost of transmission facilities in RTO/ISO and non-RTO/ISO regions (referred to as an "Independent Transmission Monitor").¹²⁵ However, the Commission did not propose to require transmission providers to establish an Independent Transmission Monitor or otherwise require additional oversight over local or regional transmission planning processes in the NOPR. Notably, the Commission will be holding a technical conference on October 6, 2022, where panelists will discuss, among other things, the possibility of establishing a role for an Independent Transmission Monitor to the extent it is consistent with the Commission's authority.¹²⁶ Nonetheless, several commenters requested that

¹²³ Enel NOPR Comments at 5.

¹²⁴ See PJM ANOPR Reply Comments at 15-20.

¹²⁵ ANOPR at P 163.

¹²⁶ See *Transmission Planning and Cost Management*, Docket No. AD22-8-000, Supplemental Notice of Technical Conference, at 9 (Sept. 8, 2022).

the Commission require the establishment of an Independent Transmission Monitor in the Final Rule in this docket.¹²⁷

As PJM explained in its ANOPR Initial Comments,¹²⁸ the Commission has previously found that although there may be benefits to be gained from independent third party oversight, transmission providers, customers and other stakeholders should determine for themselves in developing their regional planning process whether and, if so, how to utilize an independent third party.¹²⁹ PJM further explained that, consistent with the requirements of Order Nos. 890 and 1000, PJM has a coordinated open and transparent planning process, as well as meaningful dispute resolution processes for both planning and generator interconnection projects. Accordingly, PJM urged that absent any evidence that an independent RTO, like PJM, is not implementing its regional transmission planning process in a just, reasonable and not unduly discriminatory or preferential manner, the Commission should follow its decision in Order No. 890, and allow independent RTOs to address concerns related to oversight of local or regional transmission planning processes by continuing to demonstrate that they have a coordinated open and transparent planning process and meaningful dispute resolution processes.¹³⁰ This would be far more efficient than simply creating another independent entity to review an independent entity.

¹²⁷ See, e.g., *Docket No. RM21-17*, Comments of Office of the People’s Counsel for the District of Columbia and the Maryland Office of People’s Counsel, at 40-41 (Aug. 17, 2022); NJ BPU Initial Comments at 34-35; *Docket No. RM21-17*, Initial Comments of Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler, at 25 (Aug. 17, 2022); *Docket No. RM21-17*, Initial Comments of National Association of State Utility Consumer Advocates, at 6-7 (Aug. 17, 2022); *Docket No. RM21-17*, Comments Supporting Long-Term Regional Transmission Planning with Costs Allocated to the Consumers who Benefit for Network Upgrades for Generation Interconnections by The Office of the Ohio Consumers’ Counsel, at 36-38 (Aug. 17, 2022).

¹²⁸ See PJM Initial ANOPR Comments at 75-80.

¹²⁹ See *id.* at 75 (citing Order No. 890-A at P 258).

¹³⁰ See *id.* at 75-80.

PJM further explained that if the Commission were to require an Independent Transmission Monitor, it would be far more appropriate to begin this initiative in areas where there is no structural independence as between the transmission planner and its generation affiliates.¹³¹ Additionally, PJM suggested that, rather than simply layering another level of independent oversight onto a Commission-approved independent RTO/ISO, the oversight function over costs of transmission and the prudence of those investments not reviewed through the RTEP process are best addressed by improving customers' ability to make their voices heard through the Commission's regulatory process.¹³²

Moreover, the function of an Independent Transmission Monitor would be different from that of an Independent Market Monitor. PJM's Independent Market Monitor is responsible for guarding against the exercise of market power in PJM's markets and assisting in the maintenance of competitive and nondiscriminatory markets in PJM. Market Monitoring was established as an RTO requirement under Order No. 2000 in recognition of the fact that prices under a market-based regime are being set every five minutes as well as hourly.¹³³ As a result, the Commission found that its traditional regulatory tools to examine the reasonableness of rates for the commodity of electricity would never be able to keep up on a real-time basis with approving individual rate levels. Order No. 2000 therefore provided a market monitor to serve as a regulatory tool to examine, in real-time, supply and demand fundamentals, patterns and concentration of ownership,

¹³¹ *See id.*

¹³² *Id.*

¹³³ *See Reg'l Transmission Orgs.*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285 (1999)), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201 (2000)), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty. v. F.E.R.C.*, 272 F.3d 607 (D.C. Cir. 2001).

trade volumes, prices, revenue, revenue adequacy, participant bids, market structure test results, the application of offer bid caps and other relevant metrics.¹³⁴

No such minute-by-minute price changes occur in the determination of the prudence and reasonableness of the costs of transmission upgrades. Project costs are added to rate base for the life of the asset unless challenged on prudence grounds. No “market” exists at that point. As a result, the traditional rationale for establishment of market monitoring for RTO markets simply does not carry over when addressing the prudence and reasonableness of costs of fixed assets being added to rate base. In PJM’s view, this is a traditional regulatory function.

In addition, the proposal for an Independent Transmission Monitor overlooks the temporal issue around costs. RTOs approve projects included in the regional transmission plan based on cost estimates. It is only after the project is actually completed and placed into service that its costs are known with certainty. And, it is those costs – not the RTOs’ estimates developed potentially years before – that are considered for rate base treatment. As a result, an Independent Transmission Monitor’s oversight of the cost estimates may provide at best only limited information relevant to the actual regulatory decision to be made once the transmission project is in service and added to a transmission owner’s rate base.

¹³⁴ *Id.*

IV. CONCLUSION

PJM respectfully requests that the Commission consider the comments set forth above and in its Initial Comments in developing a Final Rule in this docket.

Respectfully submitted,

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Dated: September 19, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties on the official Service List compiled by the Secretary in these proceedings.

Dated at Audubon, Pennsylvania this 19th day of September, 2022.

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