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	)	**Docket No. RM21-17-000**
Electric Regional Transmission	)	
Planning and Cost Allocation and	)	
Generator Interconnection	)	

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

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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.

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

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[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 processes[3] 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:

- ***<u>The Final Rule Should Address Enhanced Reliability</u>***: As PJM explained in its initial[6] and reply[7] comments addressing the Advance Notice of Proposed Rulemaking in this

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[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 process[13]);[14]

- ***<u>The Final Rule Should Avoid a Litigious, Elongated and Disparate Compliance Process</u>***: 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. 1000[15] 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 wind[17]), 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

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[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 Scenario[20] 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]

- ***<u>Factors to be Used to Develop Long-Term Scenarios</u>***: 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]

- ***<u>State and Stakeholder Input Regarding Factor and Long-Term Scenario Development</u>***: 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]

- ***<u>Use of Multiple Long-Term Scenarios</u>***: 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]

- ***<u>Use of "Best Available Data"</u>***: 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]

- ***<u>Geographic Zones</u>***: 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]

- ***<u>Aligning Interconnection Processes with Long-Term Regional Transmission Planning Processes</u>***: 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]

- ***<u>Evaluation of Benefits Associated with Transmission Facilities to Address Long-Term Needs Driven by Changes in the Resource Mix and Demand</u>***: 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

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[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.

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[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. 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]

- ***<u>The Commission Underestimates the Cost and Time Commitments Associated with Implementation of the Proposed Long-Term Regional Transmission Planning Process</u>***: 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 commissioners[40] 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.

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[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 Reliability[45] (as previously referred to as resilience)[46] as a specific Factor[47] 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

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[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

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[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***

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[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]

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[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

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[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

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[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 manner[71]:

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

Benefit	***Description***
Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement	*Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities*
Reduced loss of load probability [OR next benefit]	*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*
Reduced planning reserve margin [OR prior benefit]	*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*
Production cost savings	*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*

[72] *See* Appendix A at 7.

	for purchases and sales outside the region, called adjusted production cost savings
Reduced transmission energy losses	*Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand*
Reduced congestion due to transmission outages	*Reduced production costs during transmission outages that significantly increase transmission congestion*
Mitigation of extreme events and system contingencies	*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*
Mitigation of weather and load uncertainty	*Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns*
Capacity cost benefits from reduced peak energy losses	*Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses*
Deferred generation capacity investments	*Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas*
Access to lower-cost generation	*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)*
Increased competition	*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*[73]

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 <u>planning and expansion of transmission facilities</u> 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.

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[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]

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[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

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[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 developer[95] 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. 779[99] and 919[100] were submitted by an incumbent transmission owner and were upgrades to its existing transmission facilities.
- Proposal Nos. 560[101] and 608[102] were submitted by a nonincumbent transmission developer and were greenfield projects.

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[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.

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[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 **<u>Table 5</u>**, 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] 704[111] and 735[112]) 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,

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[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. 202[115] and 786[116]) 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. 503[117]) 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.

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[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.

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[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] 376[120] and 883[121]) 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.

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[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 requested[125] 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 process[127] to convene a competitive proposal window[128] 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

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[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

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[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 violations[138] 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

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[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

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[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 development[148] 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.

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[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]

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[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

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[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

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[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.

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[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

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[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.

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[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 Planning[173] and Interregional Transfer Capability[174] 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

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[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]

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[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.

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[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

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[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 modifications[188] 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

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[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.

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[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:

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[194] *See* Appenidx 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.

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[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

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[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.

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[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).

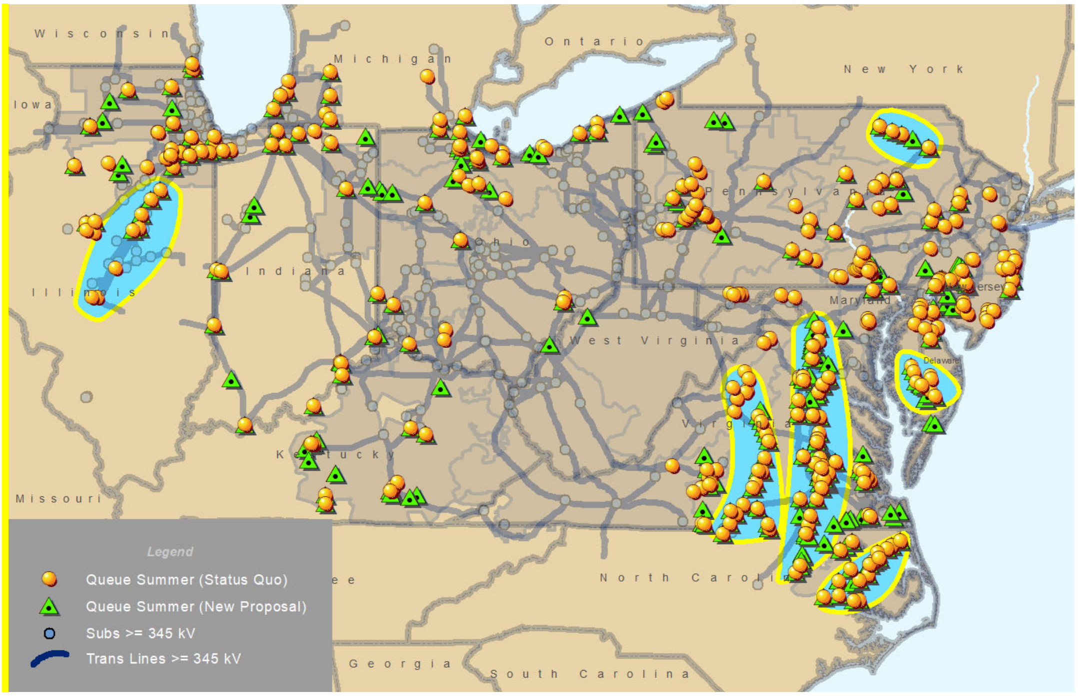
[203] NOPR at P 152.

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]

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[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

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[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.

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[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-notices/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

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[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]

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[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 queue[224] 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

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[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:

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[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.

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[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

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[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.

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[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 Reliability[238] 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

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[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-notices/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.

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[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

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[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

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[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.

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[252] *See* Section II.A.2.e(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-terms[256] 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

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[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-

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[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.

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[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 solutions[267] – 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

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[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

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[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

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[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

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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

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[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]

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[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

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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

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[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]

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[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]

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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.

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[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]

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[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

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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]

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[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

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[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 be 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 hours[320] and total estimated costs associated with several revisions proposed in the NOPR, both on an individual respondent basis[321] 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

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[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.

Respectfully submitted,

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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***
Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement	*Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities*
Reduced loss of load probability [OR next benefit]	*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*
Reduced planning reserve margin [OR prior benefit]	*While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning*

[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.

	reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements
Production cost savings	*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*
Reduced transmission energy losses	*Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand*
Reduced congestion due to transmission outages	*Reduced production costs during transmission outages that significantly increase transmission congestion*
Mitigation of extreme events and system contingencies	*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*
Mitigation of weather and load uncertainty	*Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns*
Capacity cost benefits from reduced peak energy losses	*Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses*
Deferred generation capacity investments	*Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas*
Access to lower-cost generation	*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)
Increased competition	*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 of 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	)))))	**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 management[5] due to the difficulty of predicting the timing and impact of their occurrence. Probabilities of high-impact, low frequency events are generally unknown or extremely difficult to quantify, and the consequences or impacts of high-

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

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

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

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

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

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

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

- Require that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning.

- Request that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, for any proposed market reforms and related compensation mechanisms to address resilience concerns within nine to twelve months from the issuance of a Final Order in this docket. PJM, together with its stakeholders, is already actively evaluating such potential reforms that advance operational characteristics that support reliability and resilience, including (i) improvements to its Operating Reserve market rules and to shortage pricing, (ii) improvements to its Black Start requirements, (iii) improvements to energy price formation that properly values resources based upon their reliability and resilience attributes, and (iv) integration of distributed energy resources ("DERs"), storage, and other emerging technologies. A deadline for submission of market rule reforms that the RTO feels would assist with its resilience efforts would help ensure focus on these issues in the stakeholder process.

- Request that PJM submit a subsequent filing, including any necessary proposed tariff amendments, to permit non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios. Such filings could including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[8]

- Establish improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints. With respect to interstate pipelines, PJM respectfully requests that the Commission launch

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

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

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

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

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

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

III. COMMENTS

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

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[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.

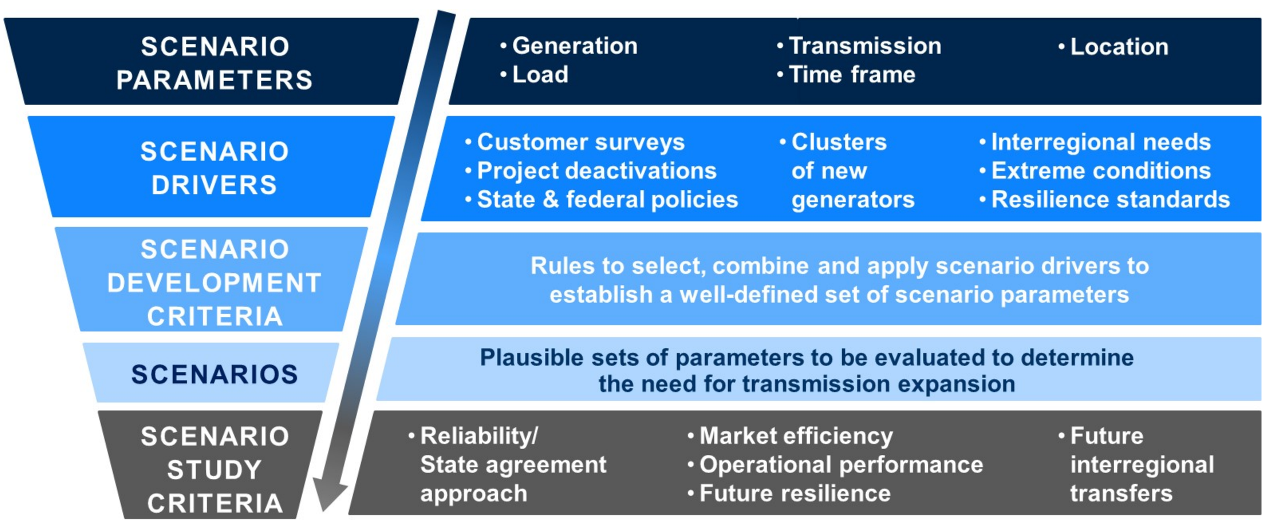
IV. Solution Details

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

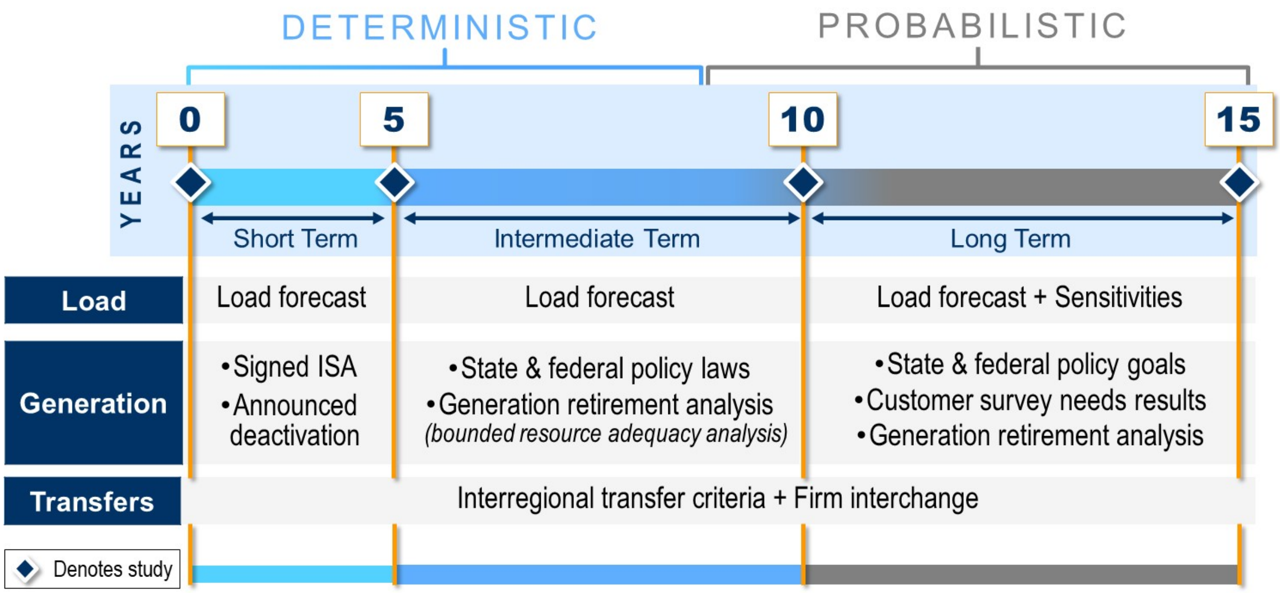
- ***Step Four – Identify if Scenario Results Are Actionable and Determine Required Time Frame***:
  - Depending on the nature and severity of the violations resulting from the above analysis, PJM would consider whether and when the issue would need to be addressed consistent with established criteria 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.