UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

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COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

I. Introduction

Sustainable FERC Project, Natural Resources Defense Council, Sierra Club, Environmental Defense Fund, Southern Environmental Law Center, Conservation Law Foundation, Western Resource Advocates, Acadia Center, NW Energy Coalition, Southface Institute, and Fresh Energy (together "Public Interest Organizations" or "PIOs") hereby submit these initial comments in response to the Federal Energy Regulatory Commission's ("FERC" or "the Commission") April 21, 2022, Notice of Proposed Rulemaking ("NOPR") proposing reforms to its regional transmission planning and cost allocation requirements.[1]

II. Executive Summary

PIOs applaud the Commission's new initiatives to make transmission planning broader, more forward-looking, fairer, and more cost-effective. In these comments we explain where the Commission's proposed revisions to transmission planning rules do not go far enough, and explain why additional measures are needed in the following areas to achieve the Commission's goals:

- Make long-term regional planning using consistent methods, scenarios, and data a mandatory practice for transmission providers in all regions;
- Require the use of specific factors in scenario planning;
- Plan transmission comprehensively and on a portfolio basis;
- Set a minimum set of benefits that must be assessed as part of all transmission planning—preferably the list included in the NOPR;
- Require transparency into and prudence reviews of local planning and require local projects to be right-sized;

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("NOPR").

- Ensure that cost allocation considers all of the benefits of transmission and ensures that states cannot delay cost allocation decisions;

- To maximize the efficacy, efficiency and consistency of transmission planning efforts, require that the scenarios and data sources developed and used for this long-term planning effort be carried over for use in each region's generation interconnection, extreme weather planning, and vulnerability assessments, as well as into interregional transmission planning; and

- Require that transmission planning entities and transmission providers in each region make good-faith efforts to implement the long-term planning results.

Eleven years ago, the Commission adopted its landmark Order No. 1000, instituting reforms to the electric transmission planning and cost allocation requirements for public utility transmission providers, with the important goal to achieve "more efficient and cost-effective regional transmission planning."[2] That rule was promulgated "in light of changing conditions in the industry."[3] Unfortunately, as discussed in PIO's Initial Comments and Reply Comments and as described in more detail below, the goals of Order No. 1000 have not been achieved.[4]

The transmission planning and cost allocation rules adopted pursuant to Order No. 1000 have failed to produce the development of significant regional transmission facilities and have produced virtually no interregional transmission facilities. Instead, Order No. 1000 unintentionally resulted in perverse incentives for public utility transmission providers to develop projects based on local, rather than regional, needs outside of regional planning processes. Because of this, data show that most transmission facilities are built outside of Order No. 1000 regional planning processes in regional transmission organizations ("RTO") or independent system operator ("ISO") regions and regional transmission planning in non-

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[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, at PP 81, 2 (2011) ("Order No. 1000").
[3] *Id.* at P 1.
[4] Comments of Public Interest Organizations (Oct. 12, 2021), Accession No. 20211012-5519 ("PIOs' Initial ANOPR Comments"); Reply Comments of Public Interest Organizations (Nov. 30, 2021), Accession No. 20211130-5284 ("PIOs' Reply ANOPR Comments").

RTO/ISO regions is essentially nonexistent. Transmission facilities that are planned outside of regional transmission planning processes are not subject to meaningful review and they fail to capture the reliability benefits and efficiencies of a regionally planned network.

Additionally, the criteria that transmission planning entities use to plan transmission fail to account for the full benefits and costs of transmission facilities. These processes consider reliability, economic, and public policy benefits in separate, overly narrow silos, which results in transmission facilities that do not capture the most benefits at the lowest cost. Further, the rules to connect new generation to the grid are wholly separate from the transmission planning process. Each of the transmission planning and generator interconnection processes makes different assumptions about what generation should be studied in the base case.

As was the case with Order No. 1000, the electric industry is again faced with major transformation of the electric system, which is driven not only by consumer preferences and state public policy, but by major decreases in the cost of renewable energy production. To ensure the continued provision of safe and reliable service at just and reasonable rates, transmission planning, cost allocation, and generator interconnection processes must account for and respond to this. To do this, FERC needs to adopt reforms that require public utility transmission providers to undertake holistic planning that recognizes all the benefits of transmission to meet the needs of future generation.

The NOPR contains enhancements that, if implemented, would likely improve the transmission planning processes in both RTO/ISO and non-RTO/ISO regions. This includes, first and foremost, requiring that all public utility transmission providers participate in regional transmission planning processes that include Long-Term Regional Transmission Planning. According to the NOPR, this requires that public utility transmission providers in each transmission planning region identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios, evaluate the benefits of regional transmission facilities to meet these needs over at least a 20 year time period, and establish criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation that address these transmission needs in collaboration with states and other stakeholders.[5]

However, a central defect in the proposed rule is that in failing to establish minimum requirements for scenario assumptions and benefit assessments, the proposed rule risks making compliance little more than a paperwork exercise. To rectify this, FERC should require foundational regional planning process requirements with a minimum set of mandatory benefits that must be assessed by public utility transmission providers, as well as a baseline set of factors and inputs that must be included in long-term scenarios.

In addition, the NOPR continues to silo public policy, economic, and reliability projects by maintaining the status quo for reliability and economic projects, essentially requiring only public policy projects to be part of long-term regional planning. As PIOs outlined in our previous comments, failure to factor in and plan for the multiple potential values of transmission facilities results in an uncoordinated overall planning approach and poorly targeted transmission facility investments, which ultimately fails to ensure the efficient expenditure of ratepayer dollars on projects that could advance multiple planning objectives.[6] At the very least, if FERC only requires that public policy projects be part of long-term scenarios, information used to make

[5] NOPR at PP 68–69.

[6] PIOs' Initial ANOPR Comments at 82 (citing The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost* (Oct. 2021*)* ("Brattle-Grid Strategies Report"), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf *in passim*).

local planning decisions must be included in long-term scenarios (including projected end of life and local reliability requirements) and local planning needs to take into account the transmission needs identified as part of long-term regional transmission planning as part of its base case.

PIOs' comments highlight simple ways that the Commission can modify its proposed rules to ensure that the transmission planning entities engage in holistic planning that considers all of the benefits of transmission and produce cost efficient and effective transmission plans that meet the needs of the electric system and consumers. First, we discuss the flaws in the current Order No. 1000 transmission planning processes. Second, we discuss our support for the Commission's scenario planning proposal, while providing evidence that FERC must incorporate specific factors into scenario planning and ensure that the existing Order No. 1000 planning processes are consistent with the reforms proposed in this rule. Third, we discuss the need for a minimum set of benefit metrics to be assessed on a portfolio basis. Fourth, we discuss the need to reform planning for local transmission. Fifth, we discuss the Commission's proposals on regional transmission cost allocation. Sixth, we show how FERC must ensure better coordination between transmission planning and interconnection rules. Seventh, we urge the Commission to mandate effective interregional transmission planning. Eighth, we discuss the underlying goals of the removal of the Right of First Refusal ("ROFR"). Finally, we discuss particular challenges with and recommendations for transmission planning in the Western interconnection.

III. The Record Demonstrates that Regional Planning in RTO/ISO and Non-RTO/ISO Regions Must Be Reformed

A. Current Transmission Planning Processes in RTO/ISOs and Non-RTO/ISO Regions Produce Unjust and Unreasonable Rates

In the NOPR, the Commission preliminarily finds that the existing regional transmission planning and cost allocation processes result in unjust, unreasonable, unduly discriminatory, and preferential Commission-jurisdictional rates because they fail to require public utility transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs; (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and (3) consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs.[7] FERC notes that these deficiencies "may be resulting in unjust and unreasonable and unduly discriminatory and preferential Commission-jurisdictional rates to the extent that they lead public utility transmission providers to fail to identify transmission needs driven by changes in the resource mix and demand, select more efficient or cost-effective transmission facilities to meet those transmission needs, and allocate the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation to meet those transmission needs in a manner that is at least roughly commensurate with the estimated benefits."[8]

PIOs strongly agree with FERC that the current transmission planning processes produce unjust and unreasonable rates and must be modified. As extensively discussed in PIOs' Initial Comments to the Advance Notice of Proposed Rulemaking ("ANOPR") in this docket,[9] and as FERC recounts in the NOPR,[10] the vast majority of transmission facilities are built outside of the Order No. 1000 transmission planning processes—either through the generator interconnection process or through local transmission planning processes. For the sake of brevity, we will not repeat the overwhelming evidence we provided in our initial ANOPR Comments here.[11] Suffice it to say that we agree with the Commission that such processes "are not designed to consider regional transmission needs and identify and select the more efficient or cost-effective

[7] *See* NOPR at P 35.
[8] *Id*. at P 47.
[9] Building for the Future Through Elec. Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021) ("ANOPR").
[10] NOPR at PP 36–42.
[11] PIOs' Initial ANOPR Comments at 31–44.

transmission facility to meet those needs" and "result in an inefficient expansion of the transmission system to meet transmission needs driven by changes in the resource mix and demand."[12]

Consumers ultimately bear the costs of these inefficiencies and suffer from the reliability risks they create.[13] Transmission is funded primarily by captive ratepayers; as such, the primary interests of monopoly utilities—maximizing investments and profit from those investments—is often in conflict with societal interests in maximizing cost efficiency and choosing clean resources while maintaining a safe and reliable electric system.[14] In this context, a core responsibility of the regulator is its disciplining publicly backed investment by ensuring that investments earning guaranteed returns are useful, prudent, and in the public interest.[15] Starting with Order No. 888, FERC has recognized that "utilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny consumers the substantial benefits of lower electricity prices."[16] As discussed in more detail in PIOs' Initial ANOPR Comments, FERC built on this in Order Nos. 890[17] and 1000 to address opportunities for undue discrimination and

[12] NOPR at P 42.
[13] *Id*. at P 43.
[14] 18 U.S.C. § 824(a); Brattle-Grid Strategies Report at 20, 23; *see also* PIOs' Initial ANOPR Comments at 7.
[15] *See, e.g.*, J. Lazar, *Electricity Regulation in the US: A Guide. Second Edition,* at Section 8.2.4: Rate Base, The Regulatory Assistance Project (2016), https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.
[16] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking*; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking ("Order No. 888 NOPR"), 60 Fed. Reg. 17,662, 17,665 (Apr. 7, 1995).
[17] *Preventing Undue Discrimination and Preference in Transmission Service*, 72 Fed. Reg. 12,266 (2007) ("Order No. 890").

underinvestment in grid infrastructure by mandating an open, transparent, and coordinated transmission planning process.[18]

While the Commission's open access and transmission planning rules have led to some significant improvements, those improvements are uneven and transmission-owner market power continues to dominate the transmission system, both within RTO/ISOs and especially in non-RTO/ISO regions where regional planning of transmission facilities is functionally nonexistent.[19] Even in RTO/ISO regions, regional transmission projects are more of an exception than the norm, and overwhelming evidence indicates that transmission owners are largely able to evade the requirements of Order No. 1000 and, in the decade since its issuance, have primarily invested in local projects.[20] This has led to a system that is failing to meet current and future needs and is ill-prepared for the rapid retirement of uneconomic generators and for fast-approaching deadlines to meet state, local and utility generation requirements—the very future threat that Order No. 1000 was attempting to address. This has also led to billions of dollars in excessive costs for consumers.[21] The Commission therefore can and must use its authority under sections 205 and 206 of the Federal Power Act ("FPA")[22] to address directly and substantively the market power abuses and undue discrimination that have led to unjust and unreasonable costs for consumers.

B. The Failures of the Current Long-Term Transmission Planning Processes are Myriad and Well Documented

As PIOs explained in our ANOPR Comments and as the NOPR preliminarily finds, most existing regional transmission planning processes do not plan on a sufficiently long-term,

[18] PIOs' Initial ANOPR Comments provide additional detail on the history of Order Nos. 890 and 1000 as related to FERC's authority over transmission planning. *See* PIOs' Initial ANOPR Comments at 20–23.
[19] *See id*. at 30.
[20] *See* Brattle-Grid Strategies Report at 19–20.
[21] *See generally id*. at Sect. I.
[22] 16 U.S.C. 824d–e.

forward-looking basis to meet transmission needs driven by trends in the resource mix and demand, leading to unjust and unreasonable rates.[23] As PIOs explained in our previous comments, the vast majority of transmission projects arise from transmission-owner internal processes and are built without competition or effective oversight, and we provided evidence demonstrating that both RTO/ISO and non-RTO/ISO regions fail to identify more efficient or cost-effective transmission facilities needed to accommodate anticipated future generation largely by avoiding the regional planning process altogether.[24] For example, between 2013 and 2017, "about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in RTO/ISO regions [was] approved outside the regional planning processes or with limited RTO/ISO stakeholder engagement."[25] This evidence demonstrates that exceptions to regional planning now drive most of the transmission projects in planning regions, and that, in non-RTO/ISO regions, regional planning is functionally non-existent.[26]

Instead of long-term, forward-looking regional and interregional transmission planning, most current planning is piecemeal and done though the generator interconnection process or local transmission planning. As PIOs explained in our ANOPR Comments, the current lack of proactive, multi-value, and scenario-based planning for anticipated future generation and policy needs has created a situation where we are planning an integrated and shared network largely through the generator interconnection process and local planning processes.[27] In addition to

[23] NOPR at P 47; *see* PIOs' Initial ANOPR Comments at 31-49.
[24] PIOs' Initial ANOPR Comments at 32–45.
[25] *Id*. at 32 (citing Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, The Brattle Group (Apr. 2019), https://www.brattle.com/wpcontent/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf).
[26] *Id*. at 32–45.
[27] PIOs' Reply ANOPR Comments at 57.

being a suboptimal way to plan the grid, having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests, resulting in inefficient outcomes and higher system-wide costs.[28] Until recently, these interconnection charges for new renewable resources typically comprised a small fraction of total project costs, but these charges have risen dramatically in recent years and now can comprise a significant percentage of overall project costs.[29] The recent NOPR proposing improvements to the interconnection process[30] would not solve the problem that too much transmission is planned through the interconnection processes and is therefore neither designed to nor sufficient to meet regional reliability, economic, and societal needs.

In addition, most current planning does not consider a broad set of benefits and beneficiaries. As PIOs explained in our ANOPR Comments, the vast majority of current transmission projects are focused solely either on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs.[31] PIOs' Initial Comments included a study by The Brattle Group and Grid Strategies[32] that showed multiple quantifiable benefits to transmission that are being ignored in the transmission planning process.[33] As a result, current transmission planning approaches and processes ignore

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[28] *Id.*
[29] *Id*.
[30] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (2022).
[31] PIOs' Initial ANOPR Comments at 49 (citing Brattle-Grid Strategies Report at iii, 2, noting that "[w]hile the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid, most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010.").
[32] Brattle-Grid Strategies Report.
[33] *See id*. at 34–35.

opportunities to benefit from economies of scale that come from “right-sizing” and strategic, comprehensive planning of transmission portfolios and projects to capture additional benefits, which include congestion relief, reduced transmission losses, resiliency to extreme weather events, increased flexibility to respond to changing market or system conditions, and facilitating larger regional or interregional solutions for cost effective interconnection of the renewable and storage resources needed to meet public policy goals. One common example of this is the routine use of in-kind replacement of aging existing transmission facilities, which “misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies.”[34]

This failure to appropriately consider and maximize a wide array of benefits also results in an unfair and inefficient allocation of costs. Because current planning methods routinely fail to consider multiple benefits across the system, they also fail to fairly allocate costs for those paying for them. Planning reactively based on individual projects instead of systematically across a portfolio underestimates multiple benefits and unfairly burdens fewer parties with these costs. It also overburdens current payors even though future parties will reap decades of benefits from today’s new transmission projects. For example, many generator interconnection-related network upgrades could be streamlined and upsized to deliver greater benefits across the system, with costs more fairly distributed among the greater number of beneficiaries.[35]

Further, in the rare instance that regional planning goes beyond these immediate needs, in most cases transmission planners still compartmentalize transmission facilities into siloed processes that separately examine projects with reliability, economic, public policy, or generator-

[34] PIOs’ Initial ANOPR Comments at 50 (citing Brattle-Grid Strategies Report at 3).
[35] *Id*. at 50–51.

interconnection benefits instead of conducting a multi-value analysis that considers them simultaneously.[36]

Overall, the failure to conduct transmission planning across a regional and interregional portfolio using a multi-value and scenario-based methodology produces an "inefficient patchwork of incremental transmission projects….limit[ing] the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks," which "systematically results in inefficient infrastructure and excessive electricity costs."[37]

IV. FERC Should Build on Its Recommendations in the NOPR to Require Robust Regional Transmission Planning and Selection Processes

In the NOPR, FERC proposes to require public utility transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, which it defines as "regional transmission planning on a sufficiently long-term, forward-looking basis to identify transmission needs 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."[38] PIOs emphatically support this proposal to require public utility transmission providers to participate in a long-term scenario planning process. However, experience with Order No. 1000 has shown that even with mandatory requirements, public utility transmission providers may only do the bare minimum necessary to comply with FERC requirements and that

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[36] *Id*. at 49–50 (citing Brattle-Grid Strategies Report at iii, 31).
[37] *Id*. at 51 (citing Brattle Report at iii, 3).
[38] NOPR at P 68; *see also id*. at 77 ("[W]e seek comment on the proposed requirement for public utility transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.").

such planning may not result in the selection, cost allocation, and construction of much needed transmission. For this reason, and as explained in more detail below, PIOs also recommend that FERC require public utility transmission planners to make good faith efforts to deliver on the results of the Long-Range Transmission Planning process by selecting recommended transmission solutions for purposes of cost allocation at the end of this process, which will help ensure that sufficient transmission is built in a just and reasonable manner.

FERC also proposes several specific requirements regarding how public utility transmission providers would implement the requirement to conduct long-term scenario planning: (1) identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios; (2) identify minimum benefit metrics that transmission planning entities must use for regional transmission facilities and evaluate those benefits over a minimum 20-year time horizon; and (3) establish criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation in collaboration with states and other stakeholders.[39] Each of these requirements is discussed in more detail below.

In the ANOPR, FERC expressed concern that regional planning processes may not adequately model future scenarios to ensure that these scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs and that, to the extent that such processes consider generation development, they tend to include only generators that have completed facilities studies and are sufficiently far along in the interconnection process to come online in the short term.[40] Such a short-term outlook under-forecasts longer-term transmission needs, preventing the development of more cost-effective transmission facilities, and fails to consider how the needs of the transmission system are shifting as a result of public policy goals,

[39] *Id*. at P 69.
[40] ANOPR at P 31.

impending retirements of uneconomic generators, potential increased demand related to electrification, and increasingly frequent and severe extreme weather events.[41] To remedy this, FERC proposes to require that public utility transmission providers develop and use Long-Term Scenarios to identify transmission needs driven by changes in the resource mix and demand across multiple scenarios that incorporate different assumptions about the future electric system over a sufficiently long-term, forward-looking transmission planning horizon.[42] PIOs fully support this requirement and offer recommendations below regarding the development of Long-Term Scenarios and their use in planning.

PIOs find FERC's proposal to leave in place the existing reliability and economic transmission planning processes pursuant to Order No. 1000 deeply problematic. As we explain in more detail below, siloing public policy projects from reliability and economic projects and exempting them from scenario-based planning risks fatally undermining the NOPR's proposed reforms. Instead, as PIOs explained in our ANOPR Comments, FERC should integrate public policy projects with economic and reliability projects where feasible to ensure that the most cost-effective projects are chosen in the planning process.[43]

V. Scenario Planning

A. 20 Years is an Appropriate Time Horizon for Developing Long-Term Scenarios

Given the long lead time to design, permit, and construct regional transmission lines, PIOs agree that 20 years is an appropriate minimum planning horizon. As FERC notes, NYISO, MISO, and other planning regions already successfully use a 20-year horizon.[44] Additionally, panelists at the November 2021 Technical Conference suggested that a 20-year planning horizon

[41] *Id*. at P 33-35.
[42] NOPR at P 84.
[43] PIOs' Initial ANOPR Comments at 81–87.
[44] *See* NOPR at P 94.

was necessary given the time needed to site, permit, and construct transmission facilities or because many states have longer-term public policy goals.[45] PIOs agree that a 20-year planning horizon will allow public utility transmission providers to better size transmission facilities to more efficiently meet not only near-term needs but also longer-term ones driven by changes in demand and the resource mix over time.

Given this long lead time, a 20-year planning horizon should be the minimum timeframe. Because the typical life of transmission assets is 40 years or more, FERC should require planning beyond 20 years as a sensitivity in the modeling. Given that transmission facilities can take 15 years to plan, permit, and construct, a 20-year planning horizon can result in "just in time" planning, where the plan is developed shortly before the process for siting and permitting must begin for even projects needed at the end of the planning period. FERC should require public utility transmission providers to take this into account and use a longer planning horizon to inform their Long-Term Scenarios.

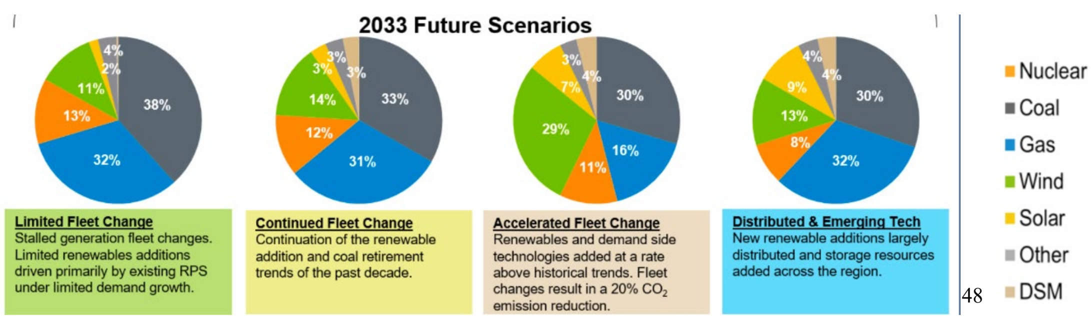
Concerns that using a 20-year planning horizon is too speculative miss the entire point of designing a range of plausible scenarios, which are not intended to try and perfectly predict the future. A shorter planning horizon will guarantee that public utility transmission providers will spend more money than necessary in the face of a changing demand and resource mix. Because of the long lead time of many of the most cost-effective transmission solutions—which as stated above typically take 15 years to design, approve and build—planning entities must look beyond the immediate future. Scenario planning is precisely the type of tool that is used to help prepare for an uncertain future: "when predictive tools reach their limits, we need to turn to strategic

[45] November 2021 Technical Conference Transcript, at 129–37 (Nov. 15, 2022), Accession No. 20220420-4001. *See also* Affidavit of Johannes P. Pfeifenberger on Behalf of the Natural Resources Defense Council ("Pfeifenberger Aff.") ¶ 27.

foresight, which takes the irreducible uncertainty of the future as a starting point . . . [t]he most recognizable tool of strategic foresight is scenario planning."[46] Moreover, there is always uncertainty in regulated industries. The regulator and regulated entities must make the best estimates possible of future conditions. In the case of planning transmission for high penetrations of location-constrained renewable resources, the resource areas are well known and unchanging.

B. Three Years is an Appropriate Planning Cycle for Long-Term Planning

FERC also proposes to require that scenarios be updated and remodeled every three years.[47] Given the speed at which the industry is transforming, PIOs agree that mandating a three-year refresh date is appropriate. For example, MISO recently recognized that the assumptions in its Transmission Expansion Planning ("MTEP") did not adequately capture the rate of change occurring in the region's fuel mix. In MTEP 2020, when MISO was planning for 2033, the MISO Futures process predicted the following fuel mixes for four different scenarios:



[48]

However, the actual MISO fuel mix in 2019 neared those percentages for the "limited fleet change" scenario in 2033 and the actual mix for 2020 neared the percentages predicted for the 2033 "limited fleet change," as the charts below show.

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[46] J. Peter Scobolic, *Learning from the Future*, Harvard Business Review (July–August 2020), https://hbr.org/2020/07/learning-from-the-future.
[47] NOPR at P 93.
[48] *See* MISO, *MTEP20 Report*, at 29, Figure 2.5-3 (2020), https://www misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc.

[49]

In other words, prior to revamping its modeling assumptions, MISO's fuel-mix 15 years out prediction was reality even before the final MTEP 2020 Report was published. This example underscores the importance of ensuring that modeling assumptions are correct. While MISO has changed its modeling assumptions for MTEP 2021, PIOs believe even the new assumptions are insufficient to capture a range of plausible futures in this rapidly transforming industry.

Some commenters may argue that three years is too short of a time to complete a scenario before beginning another assessment. However, the industry is experiencing unpredictable changes in costs, extreme weather impacts, and new technologies. Moreover, to the extent public utility transmission providers fail to adequately define appropriate bookended scenarios—i.e., to the extent their scenarios are all too conservative or too aggressive—a frequent refresh will remedy that problem.

C. FERC Should Require the Incorporation of Specific Factors to be Used in Scenario Planning

It is critical that FERC require public utility transmission providers to use minimum requirements for some factors in scenario planning but allow flexibility with other factors. As noted below, not only should FERC mandate specific factors, in some cases it should mandate

[49] *See id*. at 31, Figure 2.6-1; MISO, *MTEP21 Report*, at 4 (2021), https://cdn.misoenergy.org/MTEP21%20Full%20Report%20including%20Executive%20Summary611674.pdf.

specific values for those factors. While PIOs believe that the seven-factor list specified in the NOPR is a good start,[50] we recommend some clarifications and expansions as we explained in our Reply ANOPR Comments and as more fully set forth below.[51]

PIOs agree that, for all Long-Term Scenarios, FERC should mandate full compliance with all binding laws, regulations, public utility commission decisions, and contracts, including: (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"; and (3) "state-approved utility integrated resource plans and expected supply obligations for load serving entities."[52]

FERC should also mandate that public utility transmission providers incorporate into their Long-Term Scenarios estimates of consumer demand such as "utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand."[53] Like public officials and their constituencies, investor-owned utilities that have established and publicly announced these commitments have made promises to their shareholders and should be held to those promises.[54] FERC's proposal to provide complete discretion in assigning discounts could enable public utility transmission providers whose incentives are misaligned with consumers to game the modeling results, resulting in status quo

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[50] *See* NOPR at P 104. These are: "(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." (internal citations omitted).

[51] PIOs' Reply ANOPR Comments at 50–51.

[52] NOPR at P 104; *see* PIO's Reply ANOPR Comments at 47.

[53] *See* NOPR at P 104.

[54] This should include statements made by investor-owned utilities to the SEC or other relevant federal agencies as required by any future promulgated rules.

regional planning.[55] Similarly, the Commission should require Load-Serving Entities to provide their generation and load forecasts to the planning entities so that planners have reasonable information to use, and do not have to perform their own estimates.

Similarly, FERC's proposal to allow complete discretion for defining "trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation,"[56] could empower public utility transmission providers with incentives misaligned with consumers to game the modeling process resulting in Long-Term Scenarios that are meaningless. Moreover, requiring that transmission planning regions use the same data inputs in their regional modeling would likely assist in inter-regional modeling efforts. A better approach would be for FERC to require the use of "best available data" and publish a regularly updated list of databases that meet this requirement and require specific justification of any departure from the use of that database. For example, current databases that might meet this requirement are: National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB")[57] for technology data, Department of Energy's Annual Energy Outlook ("AEO")[58] for fuel costs, and NREL's Electrification Futures Study ("EFS")[59] for electrification trends.[60] FERC could also consider partnering with the Department of Energy, as well as the National Laboratories, to identify and develop appropriate databases. The recently enacted Inflation Reduction Act includes, among other authorities and funding related to transmission, funding for the Department of Energy to "to conduct planning, modeling,

[55] A description of PIOs concerns about utilities with incentives misaligned with consumers can be found at PIOs' Reply ANOPR Comments at 49.
[56] *See* NOPR at P 104.
[57] *See* NREL, *Annual Technology Baseline*, https://atb.nrel.gov/ (Accessed Aug. 16, 2022).
[58] *See* U.S. Energy Information Administration, *Annual Energy Outlook 2022*, https://www.eia.gov/outlooks/aeo/ (Accessed Aug. 16, 2022).
[59] *See* NREL, *Electrification Futures Study*, https://www.nrel.gov/analysis/electrification-futures html (Accessed Aug. 16, 2022).
[60] *See* NOPR at PP 107, 134; *see also* PIOs' Reply ANOPR Comments at 51.

and analysis regarding interregional electricity transmission and transmission of electricity that is generated by offshore wind."[61] A portion of this funding, or other relevant Department of Energy or National Laboratory funding, could be used to ensure that appropriate databases exist to provide high quality and consistent data for use in the planning process and to assist public utility transmission providers and other planning participants in using those databases. The Commission could also require that public utility transmission providers use consistent data across different system planning and design activities, including transmission planning, interconnection planning and studies, and reliability and extreme weather planning and studies.

Recognizing that the best available data may change over time, the Commission could provide an updated list of acceptable data sources on its website that are presumptively compliant with this requirement. If a public utility transmission provider seeks to use a database that is not on this list, FERC should require that the public utility transmission provider submit an "evaluation of the data source entities' historical accuracy in identifying and projecting trends that impact the resource mix and demand."[62] Additionally, for data needs that are not addressed in the database used by the public utility transmission provider, applying the "best-available-data" standard is appropriate as PIOs argued in our Reply ANOPR Comments.[63]

Transparency is crucial for scenario planning. If data sources are not public, stakeholders have no way to validate the accuracy of the data or argue for different, more accurate sources. Regardless of how the Commission chooses to regulate which best available data sources are used in the planning process, it should require data transparency.

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[61] Inflation Reduction Act of 2022, H.R. 5376, 117th Congress (2022), https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_of_2022.pdf.
[62] NOPR at P 134.
[63] *See* PIOs' Reply ANOPR Comments at 43–44.

PIOs agree that FERC should mandate that public utility transmission providers use trends in resource retirements,[64] but FERC should also require that public utility transmission providers specify how they will use data on generator age and condition to predict specific retirements. And, of course, FERC should require that announced retirements be included in the Long-Term Scenarios. FERC should also mandate that planning regions specify how they will reflect trends and incentives for distributed energy resources ("DERs"), demand response ("DR"), energy efficiency ("EE"), and electrification in their planning factors.[65] For example, FERC should require planning regions to specify how they will quantify trends in DERs and EE and how those values will be incorporated into the Long-Term Scenarios.

FERC proposes that at least one of the scenarios "account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events."[66] Given the increased occurrence of extreme weather events and the importance of regional reliability lines in mitigating the impacts of extreme weather events, PIOs urge FERC to require that extreme weather events be modeled through sensitivities in each scenario.[67] Further, such consideration can "reduce the considerable risks that the industry and its customers face in both the short- and long-term."[68] Specifically, PIOs recommend that FERC mandate that at least extreme heat and/or extreme cold be modeled over geographic areas that are experiencing these phenomena.

[64] *See* NOPR at P 107 ("Second, we propose to require that each Long-Term Scenario that public utility transmission providers use in Long-Term Regional Transmission Planning include trends in…resource retirements").
[65] *See* PIOs' Reply ANOPR Comments at 50–51.
[66] NOPR at P 124.
[67] *See* PIOs' Reply ANOPR Comments at 50–51.
[68] *See* Pfeifenberger Aff. ¶ 34.

PIOs support FERC's proposal to require planning regions to post their list of long-term scenario planning factors on a public website to enable stakeholder comment on those factors.[69] Obtaining stakeholder comment on discretionary factors is especially important.

PIOs applaud FERC's requirement that planning regions "more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes."[70] In addition, FERC should mandate that planning regions specify how they will reflect increases in the efficiency of the existing grid through the use of all types of grid-enhancing technologies ("GETs").[71]

D. Number and Range of Scenarios

PIOs appreciate that the Commission intends to mandate a certain minimum number of Long-Term Scenarios. As we highlighted in our ANOPR Comments, in proper scenario planning, there should be a range of plausible scenarios with at least two scenarios reflecting "bookends" of the plausible future.[72] However, the Commission's description and use of scenarios in the NOPR is problematic for several reasons.

First, given how rapidly the electric industry is changing, when looking 20 years out, the phrase "business-as-usual" is misleading and we recommend the Commission not use it.[73] This industry has been experiencing and continues to experience rapid change, and most of the changes regarding the future resource mix are in public laws and utility regulatory filings to the SEC and other entities; the only question is how rapid this change will occur and in what areas.

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[69] *See* NOPR at P 109.
[70] *Id*. at P 3.
[71] *See* Pfeifenberger Aff. ¶¶ 20–23.
[72] *See* PIOs' Reply ANOPR Comments at 36-39, 47-48, 51.
[73] *See* NOPR at P 114; PIOs' Reply ANOPR Comments at 47–48; Kees Van Der Heijden, Scenarios: The Art of Strategic Conversation, at 56 (2d ed. 2005) ("Strategising only on the basis of Business-As-Usual is fighting yesterday's war and is doomed to fail."), http://www.untag-smd.ac.id/files/Perpustakaan_Digital_1/CREATIVE%20THINKING%20Scenarios,%20The%20art%20of%20strategic%20conversation.pdf.

PIOs recommend that FERC mandate that transmission planners create at least two bookends, one using assumptions reflecting a low-end of rapid change (i.e., a "Conservative Scenario") and the other bookend reflecting a high-end of rapid change (i.e., a "Rapid Scenario"). In addition, FERC also suggests that the transmission provider could select one of the scenarios as "most likely to occur."[74] This is not a wise approach for an industry that is quickly transforming. Given this rapid rate of change, none of us can predict the future. The strength of scenario planning is to look at a range of plausible future and design solutions that would work in multiple scenarios. Rather, FERC should focus on requiring transmission planners to use the scenarios to choose transmission solutions that consider risk mitigation for a least-regrets selection criteria.[75] Selecting a single scenario as the "most likely" is essentially asking transmission planners to predict the future and FERC should not allow such an approach.[76]

Second, FERC could provide discretion to the transmission planners to set the other two scenarios between the two bookends. Examples of different types of Scenarios could include the following: Rapid Adoption Technology Scenario; Rapid Cost Reduction Scenario; Rapid Electrification Scenario; Rapid Decarbonization Scenario.

Third, requiring sensitivities will ensure that various uncertainties are appropriately explored.[77] FERC should specify that if any critical variable—such as the price of natural gas—is the same in more than two scenarios, that sensitivities must be run using different values for

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[74] The NOPR states: "In developing scenarios, it is possible to create a base case scenario that is a business-as-usual scenario, or a most likely scenario, and compare that to alternative scenarios that are considered to be less likely to occur." *See* NOPR at P 114.

[75] *See* Pfeifenberger Aff. ¶ 36 ("Least regrets planning, for example, may try to select solutions that minimize the extent to which total customer costs (including reliability costs) associated with the selected solution, when compared across all scenarios and market conditions evaluated, deviate from alternative solutions that would be least-cost for only a specific scenario or market outcome.").

[76] *See* PIOs' Reply ANOPR Comments at 48.

[77] NOPR at PP 125, 126.

that variable. Examples of critical variables include natural gas, capital costs for wind, solar, short- and long-duration storage, and carbon capture and sequestration.

E. FERC Should Specify Transmission and Generation Assets to be Included in the Modeling Baseline

The NOPR proposes that the transmission planning entities should evaluate regional transmission facilities that the "utility 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)."[78] We support incorporating generators in the interconnection queue into regional transmission planning. As we stated in our ANOPR Comments, many generator interconnection-related network upgrades could be streamlined and upsized to deliver greater benefits across the system with costs more fairly distributed among the greater number of beneficiaries.[79] Incorporating transmission needed to serve generators in the interconnection queue into the transmission planning process will help plan more efficient transmission at lower costs.[80]

However, FERC should specify what categories of transmission and generation should be presumed as existent and operational in the 20-year planning year, i.e., what assets are included in the modeling base-case before moving into expansion modeling.[81] For example, FERC should require that all models include the following: (1) for states that do not have integrated resource plans ("IRPs"),[82] plans for new generation, new storage, new grid enhancing technologies, and generation retirements for at least 10 years out, or longer if available, which FERC should require be confidentially submitted to their relevant planning authorities; (2) transmission lines

[78] NOPR at P 166.
[79] PIOs' Initial ANOPR Comments at 51.
[80] *See* Pfeifenberger Aff. ¶ 40.
[81] *See* PIOs Reply ANOPR Comments at 51.
[82] As noted above, for states with IRPs, those IRPs are binding and should be included without any discount.

that have been studied and approved by the transmission provider; (3) generators with signed generation interconnection agreements; and (4) generators that are in the latter stages of the interconnection processes.

In addition, FERC could also require that transmission planners "identify multi-value transmission solutions that can most cost-effectively create the 'headroom' necessary to interconnect the generating resources necessary to meet the region's and its individual states' public-policy requirements," which will also provide "substantial economic benefits and facilitate the more cost-effective interconnection of the generating resources necessary to meet long-term state public policy goals in addition to reliability and economic needs."[83]

FERC should also require that all public utility transmission providers, when evaluating proposed transmission solutions, determine whether any regional projects would obviate the need for multiple local projects, to replace aging assets, or whether replacement of aging assets could be adjusted or optimized to address other transmission needs at the same time.[84] To this end, FERC should determine how best to ensure that public utility transmission providers have current data on the age, condition, and estimated date for replacement of the transmission assets in their footprint.

VI. Benefits

A. In Order to Avoid the Failures of Order No. 1000, FERC Needs to Require Holistic Planning and a Minimum Set of Benefits That All Planning Regions Must Meet

The Commission has rightly identified the critical need to reform how the benefits associated with transmission are assessed in order to address the currently inefficient

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[83] *See* Pfeifenberger Aff. ¶ 41.
[84] PIOs' Initial ANOPR Comments at 50–51 ("[T]he routine use of in-kind replacement of aging existing facilities… 'misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies.'" (citing Brattle-Grid Strategies Report at 3)).

transmission planning processes that have led to unjust and unreasonable rates and a nationwide transmission deficit. Effective transmission planning requires entities to evaluate transmission needs in aggregate over time and location and to assess potential solutions to those needs through an aggregated portfolio approach, rather than looking only at piecemeal projects to address individual transmission needs. Benefit metrics serve two of the most essential functions in building a reliable, resilient, and sustainable electricity grid at just and reasonable rates: (1) determining more efficient and effective solutions to solving transmission needs; and (2) ensuring that transmission costs are allocated in a manner commensurate with the benefits those projects provide. The current lack of requirements concerning benefit assessment practices is at the heart of the inability of Order No. 1000 to achieve its aim of increased regional transmission. The failure to require transmission planning entities to plan for the multiple known, calculable benefits of transmission results in piecemeal and sometimes redundant transmission investments that can overburden generators and fail to maximize efficiencies for the benefit of consumers.[85] Without getting benefit assessment requirements right, no reform effort can succeed.

The NOPR takes an important step forward in this regard. The Commission has identified a set of minimum "Long-Term Regional Transmission Benefits" it recommends be assessed as part of its mandate to perform Long-Term Regional Transmission Planning.[86] PIOs largely agree that this list is an appropriate set of minimum benefits that all transmission planners need to evaluate as part of Long-Term Regional Planning.[87]

[85] Brattle-Grid Strategies Report at 4–5, 28.
[86] NOPR at PP 184–186, 326.
[87] *See* Pfeifenberger Aff. ¶¶ 5–8. *See also* Comments of the U.S. Dept. of Energy to Advance Notice of Proposed Rulemaking, at 24 (Oct. 12, 2021) ("DOE Initial ANOPR Comments"), Accession No. 20211012-5498 ("The minimum set [of benefits] should include categories of benefits that accrue more broadly such as reduced emissions, resilience to extreme weather events, and reduced costs of meeting federal and state public policies. Categories listed in Johannes Pfeifenberger's presentation to FERC Staff provide a good starting point for discussion.") (citation omitted).

The NOPR also acknowledges the extensive evidence provided by PIOs and numerous other commenters regarding the value of holistic benefits assessment—whereby comprehensive transmission needs are evaluated system-wide and public utility transmission providers evaluate multiple proposed solutions across a portfolio rather than on a facility-by-facility basis—in driving just and efficient results.[88] Based on this evidence, the NOPR recommends that transmission planners use its proposed list of benefits and permits evaluation of transmission projects on a portfolio basis.[89]

But like Order No. 1000, the Commission's proposed rule fails to require any public utility transmission provider to actually implement these proposed reforms. Because holistic benefits assessment is so foundational to just and reasonable transmission planning and the incentives to avoid it are so well-documented,[90] the lack of firm requirements from the Commission on this issue imperils the success of its entire effort to right the wrongs of the existing system. Moreover, public utility transmission providers that fail to properly assess the comprehensive benefits that exist with any transmission project also fail to meet legal requirements to allocate costs reflective of those benefits.[91] Firm minimum requirements need not foreclose necessary flexibility or squelch innovation, but they are necessary to provide objective standards by which public utility transmission provider submissions can be evaluated.

As set forth in more detail below, in order for FERC to succeed in ensuring that transmission planning is just and reasonable, the Commission needs to (1) require that all long-term transmission needs and benefits be evaluated comprehensively on a portfolio basis; (2) establish a minimum standard for benefit metrics against which all submissions shall be

[88] NOPR at PP 232–234, 238–239; *see also, e.g.*, DOE Initial ANOPR Comments at 38–41.
[89] NOPR at PP 233–234, 249.
[90] *See* PIOs' Initial ANOPR Comments at 31–46.
[91] Order No. 1000 at PP 622, 639; *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

evaluated; and (3) ensure compatibility between existing Order No. 1000 planning processes and new Long-Term Regional Planning. And once just and reasonable regional and interregional transmission plans have been developed, the Commission must require that regional planning entities and transmission providers make good faith efforts to implement the plans and projects that pass these tests.

B. Long-Term Regional Transmission Planning Must Be Comprehensive and Assessed on a Portfolio Basis

The NOPR acknowledges repeatedly that "the absence of sufficiently long-term, comprehensive transmission planning appears to be resulting in piecemeal transmission expansion" that results in predominantly local transmission facilities, inefficient transmission investments, and unjust, unreasonable, or unduly discriminatory rates.[92] In particular, it notes that "[t]he current approach of considering only a subset of categories of benefits based on the type of transmission need that is being studied may result in inaccurate valuation of a transmission facility's benefits in Long-Term Regional Transmission Planning . . . [and] that considering only a subset of benefits in assigning the cost of Long-Term Regional Transmission Facilities may contribute to the risk of free rider problems that impede development of the more efficient or cost-effective regional transmission facilities."[93]

The NOPR emphasizes that the solution to this problem lies with "[p]roactive, forward-looking" and "more comprehensive regional transmission planning and cost-allocation processes—like the process used to plan the MISO MVP—that [are] necessary to increase the likelihood that such highly beneficial transmission infrastructure is developed."[94] The NOPR also acknowledges that "long-term benefits may be more stable or evenly distributed over time if

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[92] NOPR at PP 25–26, 33, 40–43, 47, 55, 245.
[93] *Id*. at P 325.
[94] *Id*. at PP 28, 33.

they are evaluated for a portfolio of transmission facilities rather than for a single transmission facility."[95] The Commission notes the considerable record evidence that evaluating multiple benefits across a portfolio of proposed transmission solutions, as opposed to evaluating proposed projects individually on a facility-by-facility basis, may result in significant administrative efficiencies and helps to facilitate agreement on regional cost allocation that is at least roughly commensurate with estimated benefits.[96] Recognizing the advantages of a portfolio-based planning approach, the Commission proposes to permit and strongly encourages the use of portfolio-based planning, but stops short of requiring it on the basis that doing so "may represent a significant change for many public utility transmission providers and that the potential benefits may not warrant such a change in all instances."[97] The Commission seeks comment as to whether there are certain circumstances for which a portfolio approach should be used.[98]

The Commission also seeks public comment on its current proposal to leave in place the ability of public utility transmission providers to continue with the status quo planning processes currently used under Order No. 1000 for near-term reliability and economic projects, where reliability, economic, and public policy requirements needs are identified, evaluated, and implemented through separate planning processes.[99]

PIOs' Initial ANOPR Comments included an extensive record documenting the highly detrimental role that siloed transmission planning has played in sabotaging efforts to achieve the goals of Order No. 1000 across the country, in RTO/ISO and non-RTO/ISO regions alike.[100] For example, in 2019 ISO-NE announced a solicitation for the Boston 2028 Request for Proposal.[101]

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[95] *Id*. at P 71.
[96] *Id*. at P 233.
[97] *Id*. at P 234.
[98] *Id*. at P 235.
[99] *Id*. at PP 57, 72–76.
[100] PIOs' Initial ANOPR Comments at 32–46.
[101] *See id*. at 39–40.

ISO-NE received thirty-six proposals and awarded the procurement to a proposal by New England's two largest investor-owned utilities, Eversource and National Grid, based on its assessment that the line was the least-cost solution to the limited issue identified. In doing so, ISO-NE failed to consider other projects that would have provided a wider set of benefits, such as bringing planned offshore wind to New England consumers, integrating other planned clean energy projects, and supporting the retirement of additional uneconomic fossil fuel-fired generators in the region in compliance with state decarbonization and offshore wind procurement goals.[102] In this way, ISO-NE missed an important opportunity to co-optimize the transmission needed to meet reliability objectives together with other goals such as connecting planned new generating resources to the regional grid, likely at an overall reduced cost to consumers. Other commenters have similarly observed that in order to be just, reasonable, and not unduly discriminatory, long-term regional transmission planning must comprehensively evaluate reliability, economic, and public policy drivers and benefits.[103] Even the NOPR dissent observes that comprehensive transmission reform "should not be considered in silos."[104]

PIOs strongly urge the Commission to effectuate its stated goal to achieve comprehensive transmission planning by clarifying that the Long-Term Regional Transmission Planning process established by the proposed rule incorporate not only long-term public policy requirements, but long-term regional reliability and economic needs and benefits as well. By incorporating all three

[102] *Id*.

[103] *See, e.g.,* DOE Initial ANOPR Comments at 36 ("Separating transmission facilities into 'types' hinders a comprehensive assessment of system impacts and the ability to measure benefits relative to cost, potentially resulting in suboptimal investments and outcomes. The full value stack provided by each transmission facility should be compared against other counterfactuals to optimize transmission networks and equitably allocate benefits and costs."); Joint Statement of Former Department Defense Officials, at 2–3 (Jan. 14, 2022), Accession No. 20220114-5000 ("We also encourage FERC to bridge existing siloes between economic needs, public policy requirements, and reliability, as mentioned in the ANOPR."); Comments of the American Council on Renewable Energy, at ii, 18–23 (Oct. 12, 2021), Accession No. 20211012-5488.

[104] NOPR (Danly, Comm'r, dissenting at P 28).

kinds of benefits in the Long-Term Regional Transmission Planning process, public utility transmission providers are better able to select projects with the highest benefit-to-cost ratios and that resolve potential reliability violations at least cost. Further, as suggested by Dr. Johannes Pfeifenberger of The Brattle Group, such a least cost project selection need not necessarily require transmission investments to offer net benefits in every one of the scenarios analyzed.[105] This would "overlook the risk of regrettable future outcomes under which customers are exposed to very high costs and poor reliability because the contemplated transmission investments were not made."[106]

Additionally, in order to maximize this evaluation of multiple benefits for projects, public utility transmission providers must study projects as portfolios rather than each project in isolation. Portfolio planning can allow projects to be more than the sum of their parts by taking advantage of synergies between projects. As Dr. Pfeifenberger states, portfolio-based planning is "necessary to address the broad range of long-term transmission needs in a cost-effective fashion."[107] Long-term transmission needs cannot be individually siloed, rather, they "occur simultaneously and tend to cover large geographic areas."[108] When evaluated together, separate projects that are each designed to reduce congestion on different parts of the transmission system may create public policy, economic, and/or reliability benefits that would simply not exist if only one of the projects were constructed. For example, when a transmission project that could open up generation development to a traditionally underserved rural community is evaluated alone, the costs to build the project might exceed its benefits. But when evaluated with another project that relieves congestion to a dense load pocket in an environmental justice community, the two

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[105] *See* Pfeifenberger Aff. ¶¶ 37–39.
[106] *Id.* ¶ 38.
[107] *See id.* ¶ 30.
[108] *Id.*

projects together might create power flows across the system that would not be possible without both projects—also creating public policy, economic, and/or reliability benefits that would not have existed if the projects were not evaluated together. The Commission also acknowledges that "a more stable or even distribution of benefits from a portfolio of transmission facilities may also facilitate agreement on regional cost allocation that is at least roughly commensurate with estimated benefits."[109]

PIOs recommend that while public utility transmission providers be allowed to continue to handle unforeseen and short-term local reliability needs—those that are planned and executed within five years—in a separate process if they prefer, because the NOPR proposes to have long-term planning on a three-year cycle, the final rule should establish a rebuttable requirement that all long-term (i.e., over five years) economic, public policy, and regional reliability needs and benefits be assessed on a system-wide (i.e., a portfolio basis) within the long-term planning process. The targeted near-term planning processes should "only be used to 'fill in' the more urgent and missing pieces—such as local and lower-voltage transmission needs that may not be addressed through the approved multi-value transmission projects."[110] As discussed in more depth elsewhere herein,[111] PIOs recommend that timing and assumptions be harmonized between the long-term and near-term planning processes to avoid duplicative effort, arrive at consistent results, and ensure that the near-term planning process truly becomes a residual process, handling only those projects properly left unaddressed by long-term planning.

Public utility transmission providers, and their stakeholders, should not be allowed to delay consideration of reliability or economic needs to ensure they are only considered through

[109] NOPR at P 233.
[110] *See* Pfeifenberger Aff. ¶ 44.
[111] *See* Sect. VII at 43, *infra*.

the current Order No. 1000 process. Because, as discussed above, transmission can take up to fifteen years to plan and construct, this would lead to a situation where known reliability needs cannot be addressed because of the time it takes to actually build the planned transmission. Thus, reliability and economic needs must be incorporated into the scenario planning process, and it should be rare that they are not.

In order to address concerns about flexibility and leave room for innovation, PIOs recommend that the final rule allow a waiver of this requirement to accommodate those RTO/ISOs that may already have or desire multiple but interrelated long-term planning processes and wish to keep them—so long as the public utility transmission provider demonstrates that these joint processes are consistent with or superior to the rule in achieving the intended result of achieving forward-looking, comprehensive transmission planning that addresses the region's long-term transmission needs while maximizing net efficiency across the regional transmission system.

Apart from being necessary to achieve the aims of the NOPR, this recommendation aligns with and effectuates much of what the NOPR already requires. For example, all the proposed minimum factors to be incorporated into Long-Term Scenarios already reflect the bulk of regional economic and long-term reliability transmission needs.[112] While there may be additional region-specific economic and long-term reliability needs not already covered by the proposed list, the NOPR would already permit the incorporation of additional categories of such factors.[113] And to the extent that a certain factor reflects something that does not exist in a region, then that region's consideration of the factor will be easy; it won't weigh on the ultimate

[112] NOPR at P 104.
[113] *Id*. at P 105.

decisions.[114] As Dr. Pfeifenberger suggests, this could be accomplished through a two-step process by which transmission planners first "*qualitatively assess* the entire set of benefits when evaluating transmission solutions to long-term regional needs," then "quantify only those benefits that are determined to apply to the specific projects analyzed."[115]

For the same reasons set forth in the NOPR, economic and long-term reliability planning lend themselves both to a twenty-year planning horizon and proposed schedule of recurring three year assessments.[116] Moreover, as the NOPR is designed to identify and address system-wide transmission needs across a region on an integrated, synergistic basis, it would be grossly inefficient to evaluate proposed solutions on a project-by-project basis—especially if they were further subdivided into reliability, economic, and public policy projects. Consequently, expanding the NOPR proposal to require economic and long-term reliability planning creates planning efficiencies rather than extra burdens to transmission providers and will avoid creating the proverbial loophole that swallows the rule.

The failure to require comprehensive, portfolio-based planning also threatens to perpetuate the core problems of Order No. 1000. Doing so leaves in place balkanized and redundant planning efforts designed to incent redundant lines and overbuilding on the local level in order to benefit incumbent shareholders, as well as clogged interconnection queues, a transmission grid that remains inadequate for the complex and interconnected needs of the future, and unjust and unreasonable rates for customers.

[114] *See* Pfeifenberger Aff. ¶ 9 ("The requirement that the full set of benefits should be considered and evaluated does not mean that all of these benefits should be quantified for every project or portfolio of projects…not every benefit on the proposed list will be relevant for every project analyzed.")
[115] *Id.*
[116] *See* NOPR at PP 97–100.

But perhaps most importantly, comprehensive portfolio-based planning provides a critically important and too-rare structure designed to incent compromise across common ground.[117] Whether in California ISO ("CAISO") or the non-RTO southeast, MISO or ISO-NE, it is undeniably clear that resource diversity is necessary for grid reliability as all resources—whether thermal or renewable—are increasingly vulnerable to extreme weather impacts. The combination of rapid technology evolution, state energy policies, and consumer choice is driving the massive increase of renewable energy development seen across queues everywhere, including in states that do not have clean energy policies. Most jurisdictions have public policy requirements as well as economic and reliability-based transmission needs. And while PIOs agree wholeheartedly that no state should be able to impose its policy costs on another state's consumers, neither should any state get to free ride on benefits it is receiving from projects paid for by others. But both of these fundamental principles require that full project benefits are calculated correctly in the transmission planning processes. It is only by doing this up-front work that consumers can be assured that they only pay for the benefits they actually receive and stakeholders can be confident that cost allocation is fair.

The success of transmission investment depends on mutual cooperation, and a just and reasonable system requires structures and incentives designed to induce stakeholder engagement and cooperation. By bringing all transmission needs to the table at once and looking at potential solutions across the system, stakeholders will be able to find a more efficient suite of solutions to address multiple transmission needs affecting different jurisdictions simultaneously, drive down costs, increase competition, and facilitate cooperation on siting and permitting. And perhaps

[117] The NOPR dissent's rhetoric regarding impending civil war between states over perceived differences in public policy hides the truth that all electricity customers—in every state—want an electricity grid that is reliable, affordable, and sustainable, which every severe weather event reveals to be increasingly under threat.

most importantly, portfolio-based planning opens up greater opportunities to bring much-needed transmission solutions to historically underserved rural communities and historically overburdened communities that might be overlooked in a narrower assessment of economic- or policy-only needs and benefits. A comprehensive and portfolio-based plan that intentionally addresses equity—as well as economic and reliability goals and benefits—is more likely to increase competition and lower costs for all customers across the system. Portfolio planning also better enables the construction of projects that would not otherwise clear cost-benefit thresholds when viewed in siloed project-specific bases, such as a project providing much needed economic development, lower prices, and greater reliability to a traditionally underserved rural community that could also provide clean energy resources necessary to shut down highly polluting peaking plants in historically overburdened communities.

Such up-front portfolio-based planning also greatly reduces the risk of lines being built that are either underutilized (*e.g.*, because it was tied to a single generation source that then goes away) or are underbuilt (*e.g.*, because it was only looking at a narrow set of potential users instead of the larger potential demand). However, it does not require states that are not actually using lines to pay for the energy policies of other states; rather, in being clear-eyed about actually assessing holistically the future needs across the region and quantifying the benefits of potential solutions across the portfolio, it is much easier to find transmission solutions that address one state's policy goals and other states' reliability needs or economic goals more efficiently than would be realized with separate projects, and to accurately determine the percentage of benefit for each group. Since the rule requires all stakeholders to participate in the planning process, once the benefits are quantified more clearly, cost allocation is also easier. It ensures clarity about what is at stake if a state pays for a line that it then controls, and other states can make determinations about what that means for them. In sum, holistic benefit assessment across the portfolio provides critical transparency to all stakeholders, makes collective decision-making easier, and ensures that the most efficient level of transmission gets built.

C. The Commission Must Set a Minimum Standard for Benefit Metrics

The NOPR proposes that the following list of benefits be considered as part of Long-Term Regional Transmission Planning:

(1) avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement;

(2) (a) reduced loss of load probability, or (b) 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.[118]

As the Commission notes and the record establishes, these proposed benefits have been demonstrated as quantifiable and have been used successfully by several different regional

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[118] NOPR at P 185.

planning entities.[119] As further discussed below, all these benefits correlate with needs and goals associated with all long-range transmission planning, which is why they should be among the absolute minimum assessment required of all public utility transmission providers.

Despite these facts, the Commission does not require public utility transmission providers to assess these benefits or to allocate costs accordingly. The NOPR states it only proposes "to require public utility transmission providers to identify what benefits they will use in Long-Term Regional Transmission Planning and explain how they will be calculated 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."[120]

As discussed above, by not actually setting the proposed list as a minimum standard, the Commission's proposal perpetuates the status quo that allows determined public utility transmission providers to use extremely narrow benefits assessments to build the transmission they want at the expense of transmission that provides more benefits to the entire region.

This is likely to further aggravate the lack of a level playing field between RTO/ISO and non-RTO/ISO regions. In general, while RTOs/ISOs do not consider all the benefits of transmission in choosing transmission in their regional plans, they consider more benefits than non-RTO regions, which generally rely on the assessments of individual utilities. Because of this, incumbent utilities put pressure on RTO/ISOs to consider fewer benefits by threatening to defect for non-RTO/ISO areas with fewer transmission planning requirements, as PIOs

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[119] *Id*. at PP 189–225. *See also* Pfeifenberger Aff. ¶ 8 ("The benefit metrics proposed by the Commission have reliably demonstrated the ability to accurately quantify proposed project benefits (or lack thereof). Accordingly, given the significant and widespread experience with this list of benefits and the quantitative methods used to estimate them, as well as the need to accurately determine the potential benefits of any transmission project in order to compare with project costs, assessing the presence or absence of the benefits on this list should be mandatory for all transmission planners.").
[120] NOPR at P 186.

documented in our initial filing.[121] The Commission should level this playing field by mandating a minimum set of benefits that all transmission planning entities must plan to.

This pattern of public utility transmission providers failing to conduct proper benefits analyses is central to the current problems with transmission planning and fails to comport with the requirements of Order No. 1000 and *Illinois Commerce Commission v. FERC* to ensure that cost allocation is commensurate with benefits, a point the Commission also acknowledges repeatedly.[122] The Commission itself draws particular attention to the critical role of the failure to accurately assess benefits, whereby "the cost-benefit analyses that are used as part of the selection process may fail to identify more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of cost allocation because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities."[123] As a result, the Commission acknowledged that "when public utility transmission providers fail to consider a broader set of benefits for transmission facilities meeting transmission needs driven by changes in the resource mix and demand, they may fail to select transmission facilities in their regional transmission plans for purposes of cost allocation that meet the transmission planning region's transmission needs more efficiently or cost-effectively."[124] Despite recognizing that failing to consider the full suite of transmission benefits can lead to poor transmission plans, the draft NOPR did not mandate that the public utility transmission providers actually use all of the calculable benefits of transmission in choosing transmission in their plans. This is a missed

[121] PIOs' Initial ANOPR Comments at 24–25.
[122] NOPR at P 53, *citing Ill. Commerce Comm'n*, 576 F.3d at 477; Order No. 1000 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).
[123] NOPR at P 53.
[124] *Id*. at P 66.

opportunity to significantly improve transmission planning processes that the Commission must rectify.

Additionally, the proposed requirement that public utility transmission providers merely explain what they did and why is so vague as to lack meaning. Consequently, determining compliance with the rule will be difficult, and enforcement, if any, will be entirely subjective.

Further, it is important to note that the costs and benefits of transmission are borne over the life of a transmission project. The NOPR proposes that costs and benefits be calculated from, "at a minimum, 20 years starting from the estimated in-service date of the transmission facilities."[125] We agree that this is the minimum timeframe over which costs and benefits must be calculated. However, it is generally preferable to align this period to the useful life of the transmission project.[126] As Dr. Pfeifenberger states, several RTOs currently calculate the cost and benefits of transmission over the forty to fifty year cost-recovery lifespan of the transmission asset.[127] Calculating the costs and benefits of transmission on a shorter timespan may understate the benefit-cost ratio of the investment "because benefits tend to grow over time (e.g., with fuel costs, load growth, and more stringent clean-energy and emissions standards), while project costs (i.e., transmission revenue requirements) will tend to decline over time as the asset is depreciated."[128] As Dr. Pfeifenberger shows, "[a] benefit-cost analysis that compares only the first 20 years of (typically increasing) benefits with the first 20 years of (declining) transmission revenue requirements will understate the overall cost effectiveness of the investment."[129] For

[125] NOPR at P 53.
[126] Pfeifenberger Aff. ¶¶ 24–29.
[127] *Id.* ¶ 28.
[128] *Id.*
[129] *Id.*

this reason, "the time horizon over which economic benefits are compared to project costs should be at least 40 years to cover the cost-recovery period of the projects evaluated."[130]

In order to ensure that the final rule corrects the systemic failures the Commission has identified, it needs to set a mandatory minimum standard against which compliance on benefits assessments for transmission plans will be judged. Again, a mandated minimum need not be burdensome and has room for flexibility where appropriate. The Commission has already acknowledged that this list is a recommended floor and not a ceiling on the benefits that could be considered. Similarly, the Commission can approve screening tools that public utility transmission providers can use to reduce analytic burdens in administering this list and can allow providers to self-certify compliance and/or provide justifications for when benefits do not apply.

D. There is Strong Record Support for the NOPR's Proposed List of Benefits

The proposed list of benefits in the NOPR finds considerable record support, including extensive expert testimony provided by The Brattle Group and Grid Strategies among many others.[131] PIOs believe that it forms an appropriate basis for a minimum standard of benefits that would apply to most, if not all, regional transmission projects, and would address the Long-Term Regional Transmission Planning proposal. The Commission should make clear that these benefits should be assessed as part of any transmission planning process—even those conducted for economic purposes.

The Brattle Report provides ample support for the list of benefits in the NOPR. Brattle states that "planning needs to consider multiple values offered by transmission investments offered by transmission investments [], irrespective of whether the primary driver of transmission infrastructure is based on reliability, public policy, or economic needs" results in

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[130] *Id.* at 29.
[131] *See* Brattle-Grid Strategies Report at 30. *See also* Pfeifenberger Aff. ¶¶ 5–8.

"lower overall costs to customers."[132] To allow public utility transmission providers to leave these cost savings on the cutting room floor will ultimately raise costs for consumers and result in an inefficient transmission plan. Table 4 of the Brattle Report puts in stark relief all the benefits of transmission that are currently not quantified, to consumers' detriment.[133] And this only includes the RTO/ISO regions. The issue is more dire in the non-RTO planning regions.

TABLE 4. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
<u>Quantified</u> 1. production cost savings value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	<u>Quantified</u> 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	<u>Quantified</u> 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	<u>Quantified</u> 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
<u>Not Quantified</u> 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	<u>Not Quantified</u> 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO2 emissions 11. decreased wind volatility 12. increased local investment and job creation	<u>Not Quantified</u> 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	<u>Not Quantified</u> 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

Sources: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity; Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

The Brattle-Grid Strategies Report also provides sufficient evidence that the transmission-related benefits that some commenters may argue are difficult to quantify are anything but.[134] While we do not repeat here every argument in the Brattle-Grid Strategies

[132] Brattle-Grid Strategies Report at 30–58, App. A (listing several studies using multi-value benefits analyses), App. B (providing further detail on expanded transmission benefits). *See also* Pfeifenberger Aff. ¶¶ 14–19.
[133] *Id.* at 31, Table 4.
[134] *Id*. at 31–58, App. B.

Report and PIO's Initial ANOPR Comments, they provide evidence that "RTOs and transmission planners are increasingly recognizing that traditional production cost simulations are quite limited in their ability to estimate the full congestion relief and production cost benefits."[135] Appendix B to the Brattle-Grid Strategies Report provides significant evidence on how to quantify additional production cost savings that are currently missed. It also provides evidence on how to quantify reliability and resource adequacy benefits—including benefits from avoided or deferred reliability projects and aging infrastructure replacement, reduced loss of load probability, and lower planning reserve margins.[136] The report also shows how to quantify generation capacity value and market, environmental, and public policy benefits among others.[137]

In addition to this list, PIOs strongly recommend that benefits associated with projects that enhance resiliency in the face of extreme weather impacts be included in the list. Given the pendency of the Commission's approach to extreme weather events,[138] it is not yet possible to say exactly how those benefits are to be quantified and included in transmission planning. For example, if extreme weather events end up being treated as a factor that must be considered in resource adequacy planning, transmission could bring economic benefits by reducing the cost of meeting new resource adequacy requirements. On the other hand, if extreme weather risk is reflected in a need for greater contingency tolerance in the transmission system, it would result in new transmission reliability criteria. Regardless of the ultimate determination on how to manage extreme weather risk, both the final rule in this rulemaking and in the Extreme Weather

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[135] *Id.* at 36.
[136] Brattle-Grid Strategies Report at 36–43.
[137] *Id*. at 43–53, App. B.
[138] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (2022); *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, 179 FERC ¶ 61,196 (2022).

rulemaking should both require transmission planners to consider transmission solutions in the long-term regional transmission planning in a manner consistent with any new requirements arising from the Extreme Weather rulemaking.

Additionally, as recommended by the Department of Energy ("DOE"), long-term transmission planning should include benefits associated with impacts on historically overburdened communities.[139] PIOs agree with DOE that:

> Any methodology used for assigning benefits should incorporate a socio-demographic dimension to disaggregate the impacts and capture the specific benefits (economic, resilience, environmental and public health) to historically underserved communities. Such methodologies should also identify the communities directly harmed by the installation of transmission lines in their territories, utilizing a cumulative impact analysis. Finally, the methodology should include transparent communication with communities concerning the positive and negative impacts of transmission expansion projects.[140]

VII. Relationship between Long Term and Order No. 1000 Reliability and Economic Planning

A. Long Term and Order No. 1000 Planning Should be Based on a Consistent View of the Future

The NOPR envisions retaining the current Order No. 1000 planning process to identify "near-term reliability and economic needs" while the new long-term regional transmission planning evaluates longer term needs in parallel.[141] FERC seeks comment on whether public utility transmission providers should be required to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes to identify more efficient or cost-effective transmission facilities than are identified through those processes today. As discussed above in the section on benefits, FERC must make clear that the long-term

[139] *See* DOE Initial ANOPR Comments at 4, 24.
[140] *Id*. at 38–39.
[141] NOPR at PP 3, 89–90.

regional transmission planning process must plan for long-term reliability and economic needs. This means that only reliability or economic needs that arise in the *near term* can continue to be addressed under current processes.

However, to the extent the two processes continue to exist, at a minimum, FERC needs to require both processes be based on a consistent view of the future. Allowing two separate transmission processes risks creating two planning processes based on different assumptions. In contrast with the scenario-based approach under consideration here, Order No. 1000 planning often uses a "base case" which is the planner's best assessment of future conditions. In addition to the obvious duplication of effort, retaining both approaches risks planning based on inconsistent assumptions, thus undermining the goals of this NOPR. Inconsistent assumptions could easily lead to redundant projects or failure to identify more efficient solutions to emerging transmission needs. In particular, if the Order No. 1000 base case identifies transmission needs that are not anticipated in long-term regional transmission planning scenarios, the opportunities for more efficient planning created by the long-term process will be lost. More subtly, if stakeholders can foresee different outcomes from the two planning processes, there will be motivation to undermine the long-term regional transmission planning when they believe the Order No. 1000 planning will produce results more favorable to them.

The Commission should avoid this outcome by mandating that long-term regional transmission planning scenarios and Order No. 1000 base cases are defined in the same process. This will likely be less of a change to Order No. 1000 planning than it might seem. Because uncertainty grows the further one looks to the future, long-term regional transmission planning scenarios should not diverge significantly over the relatively short planning horizon used for most Order No. 1000 planning. Indeed, significantly different short-term results between the long-term regional transmission planning and Order No. 1000 planning is likely indicative of one scenario's flawed assumptions being used in the other.

Further, if the Commission preserves the existing near-term Order No. 1000 planning processes, it needs to widen their scope to include multi-value planning.[142] As shown in our initial ANOPR Comments, existing planning processes often are inefficient in that they are overly siloed to address specific needs, such as reliability needs, without considering other transmission needs, such as market efficiency and public policy needs. To the extent that a transmission need is identified but not addressed in the long term planning process (something that should happen extremely rarely), this need must roll into the near-term process to avoid the situation in which the near-term Order No. 1000 process generates a solution that solves a narrowly-defined need and pre-empts a multi-value solutions that could more cost-effectively address multiple needs, as is currently frequently occurring.[143]

There is a variety of approaches that would result in consistent planning assumptions between the two processes. For example, MISO currently uses scenario planning in its Order No. 1000 process. Planners could simply include Order No. 1000 assumptions as one scenario for the long-term regional transmission planning, or the long-term regional transmission planning process could result in a "consensus scenario" that represents the near future for Order No. 1000 purposes. Thus, PIOs do not request the Commission be overly proscriptive in how to harmonize the two planning processes. Rather, we recommend that a final rule in this docket include a requirement that each planning region base its Order No. 1000 planning and long-term regional transmission planning on consistent views of the future that arise from a single process.

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[142] *See* Pfeifenberger Aff. ¶¶ 46–47.
[143] *See id.* ¶ 45.

B. Timing Between Order No. 1000 Planning and Long-term Regional Transmission Planning Must be Aligned

To the extent that FERC maintains separate long-term and Order No. 1000 planning processes, it must make sure the timing of the various transmission planning processes aligns. Order No. 1000 planning operates on its own cycles and planning windows which vary between planning regions. This creates a risk that the two planning processes operate on overlapping or otherwise unaligned schedules. That opens the door to inconsistent assumptions and uncoordinated project identification between the two processes. At the very least, operating two independent, unsynchronized planning processes creates confusion and administrative burden.

PIOs suggest that FERC direct planners adjust the timing of their Order No. 1000 planning cycles to align with long-term regional transmission planning. This entails four common sense adjustments:

- Mandate that Order No. 1000 planning cycles be no longer than long-term regional transmission planning cycles, and, if shorter, evenly divide the long-term regional transmission planning cycles. For example, if a public utility transmission planner uses a thirty-six-month long-term regional transmission planning cycle, its Order No. 1000 cycles should be thirty-six, eighteen, or twelve months. This would ensure that an Order No. 1000 cycle begins coincident with each long-term regional transmission planning cycle, enabling economy of effort between the two. If the public utility transmission planner's Order No. 1000 cycles are shorter than the long-term regional transmission planning, this timing is ideal for the Order No. 1000 process to identify genuine short-term needs that arise too quickly for the long-term regional transmission planning to identify.

- Synchronize assumptions with each long-term regional transmission planning cycle. In the years when both a long-term regional transmission planning and Order No. 1000 cycle start, the planning assumptions used in the two processes should be identical.[144] Off-year Order No. 1000 cycles would be based on any updates needed to the most recent set of common assumptions. This preserves consistency between the two processes, and again, focuses the Order No. 1000 planning on genuine near-term needs.
- Clarify the time horizon for Order No. 1000 planning. Order No. 1000 long-term planning looks forward between five and twenty years,[145] If left unchanged, this would result in both Order No. 1000 planning and long-term regional transmission planning identifying solutions over the same time periods, but with different planning assumptions, benefits assessments, and cost allocation. The NOPR is ambiguous as to whether the Order No. 1000 process will be retained in its entirety or only for near-term planning.[146] This can be avoided if the Commission clarifies the time period that Order No. 1000 requirements regarding reliability and economic planning will continue to apply to.
- Require planners to specify when the results of one planning process is incorporated into the other and require all reasonable effort to avoid one process disrupting the other. Considerable wasted effort is caused when the results of one

[144] *See* Sect. 4.A.D, *infra.*
[145] *See* NOPR, n. 101.
[146] *Compare* NOPR at P 3 ("We do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers with respect to existing reliability and economic planning requirement") and P 89 ("we do not propose to require that public utility transmission providers use Long-Term Scenarios in their regional transmission planning processes to address *near-term* reliability and economic transmission needs") (emphasis added).

transmission planning process changes the assumptions used by another concurrent process. If Order No. 1000 processes and long-term regional transmission planning are not coordinated, one can easily imagine problems similar to those plaguing interconnection queues, where the long-term regional transmission planning is repeatedly disrupted by projects built through the Order No. 1000 process altering the long-term regional transmission planning's assumptions. The Commission should direct transmission planners to establish study timing and procedures for how the results of one process are incorporated into others that prevents this from occurring.

VIII. Local Planning

A. FERC Must Require Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process to Identify Potential Opportunities to Right-Size Replacement of Transmission Facilities

The Commission rightly acknowledges that in recent years most transmission projects are in-kind "local" projects,[147] including those in which a public utility transmission provider replaces an aging transmission facility with a new transmission facility that does not expand the transmission capacity of the line.[148] Because these projects are merely "rolled-up" into regional transmission plans, they are not subject to the planning requirements of Order Nos. 890 and 1000. Further, there is no requirement for transmission providers to provide information on pending in-kind transmission replacements to transmission planners, foreclosing even consideration of more efficient alternatives to in-kind replacement.[149] Public utility transmission

[147] The Commission defines this in Order 1000 as those located solely within a public utility transmission provider's retail distribution service territory, and so not subject to the cost allocation or competitive solicitation provisions of the regional transmission plan.
[148] NOPR at P 398.
[149] *Id*. at P 385.

providers have used this loophole to dramatically ramp up local transmission projects, while not building regional or interregional projects.[150] Public utility transmission providers have every incentive to rely as much as possible on local projects because these projects are typically presumed prudent, face no competition, and still bring high returns on investment.

With this increase of regional planning-exempt local projects has come a concomitant decrease in regional projects and a move away from transparent transmission planning as discussed throughout these comments.[151] While there will always be a place for some local transmission planning, PIOs are especially concerned about this trend because local transmission facilities are narrowly focused on local reliability and are not designed to facilitate regional reliability, public policy, or economic benefits. Consequently, local transmission facilities are often less beneficial to the overall system than regional projects that bring a host of benefits to many customers.

The Commission also acknowledges that in many instances transparency and stakeholder participation in local transmission planning processes do not meet the standards required by Order No. 890.[152] In particular, customers often are not included in the early stages of local planning and are too often merely given an opportunity to comment on transmission plans that were developed without customer input.[153] Just as important, public utility transmission providers do not have sufficient knowledge of when and where transmission owners intend to build local transmission facilities to adequately conduct Long-Term Transmission Planning.

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[150] *See* PIOs' Initial ANOPR Comments at 32–40.

[151] PIOs' Initial ANOPR Comments provide significant evidence of the results of this use of local planning to the detriment of regional planning. *See id*. at 32–45.

[152] NOPR at P 398.

[153] *Id*.

To address problems stemming from an overemphasis on local projects and a lack of transparency and customer input into local transmission planning, the Commission proposes two modifications. First, the Commission proposes to formalize transparency and stakeholder feedback requirements in the local project planning process, including the provision of local transmission planning information to regional planners.[154] Second, the Commission seeks to require transmission owners to make their planned local projects larger than 230 kV known to regional planners so that they can be "right-sized" to provide regional benefits.[155] We look forward to discussing these and other matters concerning local transmission projects at the Commission's October 6, 2022 technical conference.

PIOs support the Commission's proposals for how to better integrate local transmission projects into regional transmission system planning. However, the Commission should go further so that customers are not "forced to pay for less efficient or cost-effective investment in transmission facilities"[156]. PIOs recommend that the Commission expand its reforms to the local projects planning process in several ways, all aimed at ensuring that the needs driving local projects can be fully considered in regional planning. First, the Commission should improve prudence review of local projects, including eliminating the presumption of reasonableness for local projects to meet needs that have not been incorporated into the regional planning process, and reducing the rate of return on local projects. Second, the Commission should require public utility transmission providers to submit transmission planning information to the planning region in enough time not only for stakeholders to review and provide feedback on planned local projects, but also in time for regional planning processes to effectively find, propose, approve,

[154] *Id*. at P 400.
[155] *Id*. at P 403.
[156] *Id.* at P 33.

and construct regional alternatives where appropriate. Third, the Commission should require public utility transmission providers to package local projects together where possible to take advantage of economies of scale, reduce the number of local projects, and/or increase the benefits of local projects. Fourth, the Commission should extend information reporting requirements to ensure that transmission planning entities are made aware of future in-kind replacement projects so they can adequately consider alternatives or right-sizing. Fifth, the Commission should require public utility transmission providers to evaluate all the benefits outlined in the NOPR, including public policy and economic benefits, of regional solutions that could replace local projects. Each of these is discussed in more detail in the following sections.

B. The Commission Should Improve Prudence Review of Local Projects

As PIOs argued in our previous comments, the Commission must make reliance on local projects less attractive to transmission owners.[157] Currently, public utility transmission providers have at least three strong incentives to avoid independent transmission planning processes in favor of reliance on local projects. First, the Commission currently presumes that local projects are prudent. Second, local projects avoid competition. Third, transmission owners see high rates of return on local transmission projects despite little to no risk to them.

The Commission can accomplish this goal by eliminating its presumption that local projects are prudent. The Commission should issue a rule or policy statement that places the burden of proof back on public utility transmission providers to demonstrate that the cost of a proposed transmission project is just and reasonable. Section 205 places few bounds on how utilities may demonstrate that rates are just and reasonable, and nothing PIOs suggest will prevent public utility transmission providers from attempting to demonstrate just and

[157] PIOs' Initial ANOPR Comments at 61–65.

reasonableness however they choose. However, the Commission could maintain the presumption of prudence for local projects if the drivers (economic, reliability, public policy, or asset replacement) of the project have been reviewed and not addressed by a regional planning process. If, however, a public utility transmission provider seeks rate recovery for a project that is presented as a "surprise," addressing needs not reported to a regional process, they would need to affirmatively demonstrate that the project is prudent through a normal prudency review.

In addition to putting the burden of demonstrating prudency back on public utility transmission providers, the Commission should modify the rate of return for local projects. These projects have no competition, are low risk, and have revenue guaranteed by the public. They inherently carry much less risk than a merchant transmission project and less even than regional projects with or without a federal ROFR. The Commission should consider some form of "ROE subtractor" analogous to the ROE adders that exist today. ROE subtractors would automatically reduce the guaranteed returns for local projects that meet certain criteria, such as lack of review by regional planners, lack of competitive bidding, or untimely identification of project need.

1. Public Utility Transmission Providers Must Provide Local Transmission Planning Information to Regional Planners Such that They Have Sufficient Time to Find, Propose, Approve, and Construct Regional Alternatives Where Applicable or Face Challenge

The Commission proposes that where public utility transmission providers provide local transmission planning information to the transmission planning region, they must do so in a manner that allows for no less than three meetings with stakeholders prior to inclusion in the regional planning process.[158] However, when transmission needs are made public with minimal lead time, there are unlikely to be meaningful alternatives to the transmission provider's

[158] NOPR at P 401.

preferred investment. Without the opportunity to incorporate local transmission needs into regional planning, the stakeholder process proposed in the NOPR will result in few if any improvements to the development of local projects. The Commission should require public utility transmission providers to identify the drivers for local projects in the LRTP planning process with enough time for the process to identify regional projects that could more efficiently or cost-effectively address the transmission need.

As detailed in PIOs' and others' previous comments, part of the problem with local project planning processes is that public utility transmission providers do not inform regional planners and stakeholders of planned local projects under any prescribed timelines or with enough time to effectively find, evaluate, and approve more cost-effective and beneficial alternatives.[159] Public utility transmission providers are free to propose local projects whenever they see fit according to their own business interests, often on timelines that are difficult to justify.[160]

While the Commission proposes minimum timelines between stakeholder meetings for evaluating local projects, it does not require that public utility transmission providers identify local project drivers to the regional planning process on any timeline outside of projects at or above 230 kV. Under the Commission's proposal, stakeholders would have a minimum of fifty days to review projects. [161] Even assuming that fifty days is sufficient time for stakeholders to provide meaningful feedback, it is virtually meaningless in the context of a three-year transmission planning cycle. The proposed fifty-day notification is not nearly enough time for

[159] *See e.g.,* PIOs' Initial ANOPR Comments at 92–94; Comments of Union of Concerned Scientists, at 24–31 (Oct. 12, 2021) ("UCS Initial ANOPR Comments"), Accession No. 20211012-5493.
[160] *See e.g.,* PIOs' Initial ANOPR Comments at 93 (describing a rise in "end of life" projects that happen on short notice and many years before the expected life of transmission assets).
[161] NOPR at P 401.

regional planners to find, evaluate, and approve regional alternatives that could provide multiple additional benefits and obviate the need for local projects, let alone for public utility transmission providers to construct any approved regional projects. Because of the time it takes to plan, site, and construct transmission, each transmission owner should be planning transmission in sufficient time so that it can be in service by the time it is needed. The Commission previously identified a problem with transmission providers identifying Immediate Need Reliability Projects with a need-by date prior to its projected in-service date, and some for which the need-by date was before the solution was chosen [162] These compressed timelines justified exempting those projects from regional planning.

This is inconsistent with Good Utility Practice and the goals of proactive holistic transmission planning.[163] Public utility transmission providers should be aware of the need for system upgrades well before the need becomes a reliability violation. To provide time for these local needs to be evaluated in the regional transmission planning process, the Commission should require each public utility transmission provider to submit, in coordination with the relevant regional planning process, a comprehensive list of all anticipated local reliability violations and forecast load growth for inclusion in at least three long term regional planning cycles. To the extent that some project needs are identified that require earlier in-service dates, the Commission should require public utility transmission providers to include these needs in the

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[162] *See ISO New England, Inc, et al*, 169 FERC ¶ 61,054 (2019).

[163] "Good Utility Practice" is defined in section 1.15 of the pro forma OATT as follows:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others,
> but rather to be acceptable practices, methods, or acts generally accepted in the region.

Pro-Forma Open Access Transmission Tariff (eff. Mar. 12, 2022), https://www ferc.gov/media/pro-forma-oatt-effective-march-14-2022.

regional transmission process as soon as possible. And in instances where project needs are identified with so little advance warning that they cannot be considered by long-term regional planning, the Commission should (1) require the public utility transmission provider to explain to the Commission why the need and solution were not identified earlier and consider this explanation in setting the return on investment allowed for the project; and (2) require the public utility transmission provider to provide an independent assessment of alternatives to the new local transmission project that mitigate the identified need until a regionally planned project and portfolio solution becomes available.

2. Public Utility Transmission Providers Must Identify and Present Projects Affecting the Same Area Together to Provide an Apples-to-Apples Comparison to Regional Alternatives

In addition to the short, seemingly arbitrary lead times often associated with local projects, too often local projects are doled out piecemeal rather than presented holistically as a set of solutions to related problems. Union of Concerned Scientists ("UCS") provided a powerful example of this in its initial ANOPR Comments.[164] UCS presented a case study of thirteen projects proposed over four years in the Columbus, Ohio area. PJM presented each of these projects individually, making any cost comparison of alternatives to an individual proposed line come up short. Had these projects been presented together, it is possible that a cheaper, more beneficial project could have been developed to meet many or all the reliability needs presented by thirteen local projects as a whole. This failure in transparency and holistic planning is emblematic of the problems regional planners currently face under the piecemeal approach public utility transmission providers rely on for the development of local projects to meet local reliability needs.

[164] *See* UCS Initial ANOPR Comments at App. A.

The Commission's proposed increase in transparency and information sharing for local projects would not resolve the issue UCS identified in Ohio. Stakeholders and regional planners need to see related local project needs together to identify better solutions. Without such grouping, stakeholders will rarely be able to propose alternatives that could save ratepayers money and reduce the number of new transmission projects. Thus, the Commission should require public utility transmission providers to present local projects that affect the same area together through the Commission's revised project transparency requirements. This highlights the importance of connecting and incorporating the generation interconnection process into the regional long-term planning process, evaluating new interconnection requests in geographic and time tranches for analytical efficiency, larger transmission solutions, and more clarity and fairness to projects in the interconnection queues.

C. The Commission Should Require Public Utility Transmission Providers to Provide Regional Planners Information on Upcoming In-Kind Replacements so They may Consider Right-sizing or Alternatives

PIOs applaud the Commission for proposing rules around right-sizing in-kind replacements of local transmission facilities by tailoring replacements to serve long-term system needs. In-kind replacements occur when old transmission projects reach the end of their life and require major investments. As such, they are inherently foreseeable, and there is no reason why the regional process should not evaluate the need for the in-kind replacement versus other alternatives. As PIOs explained in our initial comments, right-sized projects leveraging GETs can create large economies of scale to capture benefits beyond reliability, including public policy and economic benefits.[165] PIOs agree with the Commission's proposal to require public utility transmission providers to provide a list of all planned in-kind replacements at and above 230 kV

[165] PIOs' Initial ANOPR Comments at 50 (citing Brattle-Grid Strategies Report at 3).

ten years in advance. PIOs also strongly agree that right-sizing projects should be evaluated as part of the long-term regional planning process, and include not only increasing voltage, but also adding circuits and utilizing advanced technologies wherever possible.

PIOs are concerned, however, that the Commission's right-sizing requirements give public utility transmission providers too much latitude to pick and choose which right-sized projects to actually construct based only on their own financial interests. The Commission's decision to create a ROFR for right-sized projects but still give the public utility transmission provider the option to construct an in-kind local project instead of the identified right-sized project is likely to lead to unjust and unreasonable rates. Public utility transmission providers may decide to make in-kind replacements rather than right-sized replacements for any number of reasons that are not in the interest of ratepayers. Once the regional planner has identified a right-sized facility, or even an entirely different project, as providing greater benefits to the system than an in-kind replacement, there is no reason to allow the public utility transmission provider to reject the right-sized or alternative project, especially when all additional costs will be cost allocated to cost-causers and beneficiaries.

The Commission should treat its new ROFR for right-sized or alternative projects as just that: a ROFR. If the incumbent decides not to construct the right-sized or alternative project, the project should be offered to other transmission developers. Ratepayers should not lose access to investments that bring increased benefits simply because the incumbent utility chooses not to build them.

D. Local Projects Should be Compared to Regional Solutions Across all Benefits Identified in the NOPR, Including Public Policy and Economic Benefits, Rather than Against Only Reliability Benefits

While the Commission proposes to increase transparency in the local transmission planning process and to subject right-sized local projects to cost allocation, it is not requiring evaluation of alternatives to local projects—including right-sizing projects—to include benefits beyond reliability such as those enumerated in the NOPR. As discussed above and in PIOs' previous comments, it is imperative that transmission planners evaluate the benefits of projects across all potential benefits rather than in silos.

By limiting consideration of transmission projects to one benefit at a time, public utility transmission providers are missing the forest for the trees. As the MISO MVP portfolio and its new Long Range Transmission Planning Tranche 1 have proven, when transmission planners include a range of public policy and economic benefits alongside reliability benefits, regional projects suddenly become the obvious choice over the piecemeal local reliability projects that currently dominate transmission development.[166] MISO's Long Range Transmission Plan Tranche 1 produced eighteen new lines, which will provide total economic benefits that "significantly exceed costs."[167] By comprehensively assessing the benefits of transmission, MISO is providing, on average, \$2.60 in benefits for every dollar spent. That is because while the total portfolio of these new lines is estimated to cost \$10.3 billion, MISO also estimates \$37.3 billion of value from moving power around the large region.[168] FERC cannot leave this

[166] MISO's MVP portfolio had a benefit-to-cost ratio of 2.2 to 3.4. *See* MISO, *MTEP17 MVP Triennial Review*, at 4 (Sept. 2017), https://cdn misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf. MISO's new Long Range Transmission Planning Tranche 1 has a benefit-to-cost ratio of 2.6 to 3.8. *See* MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary*, at 4 (2022), https://cdn.misoenergy.org/MTEP21%20LRTP%20Tranche%201%20Executive%20Summary625362.
[167] MISO System Planning Committee of the Board of Directors, *Reliability Imperative: Long Range Transmission Planning*, at 8–9 (June 30, 2022), https://cdn misoenergy.org/20220630%20System%20Planning%20 Committee%20of%20the%20BOD%20Item%2004%20Reliability%20Imperative%20LRTP625355.pdf.
[168] *Id.* at 8.

kind of consumer benefit on the table as it sets new transmission planning requirements. Further, as with our comments on Long Term Transmission Planning above, PIOs urge the Commission to require that evaluations of alternatives to local reliability projects—especially evaluations for right-sizing in-kind projects—include a cost-benefit analysis of reliability, public policy, and economic benefits.

IX. Regional Transmission Cost Allocation

In the NOPR, FERC proposes to require that public utility transmission providers in each transmission planning region revise their Tariffs to include either (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, (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.[169] These cost allocation provisions must comply with the existing six Order No. 1000 regional cost allocation principles. FERC also proposes to require public utility transmission providers to provide states time to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any ex-ante regional cost allocation method that would otherwise apply.[170]

In Order No. 1000, the Commission required each public utility transmission provider to allocate the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation according to six cost allocation principles.[171] It did not require the use

[169] NOPR at P 303.
[170] *Id*. at P 319.
[171] Order No. 1000 at P 558. The six principles are: (1) the costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless

of specific costs or benefits to assign costs of transmission. Following Order No. 1000, the majority of public utility transmission providers allocate the costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation that address reliability needs separately from those that address economic needs, and separately from those that address transmission needs driven by public policy requirements.

Because current planning methods routinely fail to consider multiple benefits across the system, they also fail to fairly allocate costs for those paying for them. Economic benefits of reliability projects are not generally considered in cost allocation, nor are economic and reliability benefits of public policy projects. The result is that cost allocation for public policy projects appears virtually independent of those projects economic or reliability benefits.[172] In hindsight, this outcome is inconsistent with the cost allocation principles specified in Order No. 1000, and has had a chilling effect on transmission projects to support state policy—even those that may provide multiple other benefits. PIOs thus respectfully request that the Commission specifically find that cost allocation of public policy projects without consideration of economic and reliability benefits is unjust, unreasonable, and unduly discriminatory.

Additionally, as discussed in the Benefits section, a result of this siloed view of calculating benefits and assigning costs is that current transmission planning approaches and

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another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.

[172] For example, in its study of transmission needs to meet state policy goals, PJM found: "Due to the lower cost of renewable generation, the gross load payments…are lower compared to the base case. The largest decreases in gross load payments are in the District of Columbia, Delaware, Maryland, New Jersey, North Carolina, Pennsylvania and Virginia with the rest of the PJM states also enjoying load payments benefits, albeit on a smaller scale." Despite these projects bringing benefits to the entire PJM footprint, under current rules 100% of costs would be allocated to the sponsoring state(s). PJM, *Offshore Wind Transmission Study: Phase 1 Results*, at 20 (Oct. 19 2021), https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211102/20211102-informational-report-offshore-wind-transmission-study-phase-1-results.ashx.

processes ignore opportunities to benefit from economies of scale that come from modifying transmission projects to capture additional benefits, including congestion relief, reduced transmission losses, increased flexibility to respond to changing market or system conditions, and facilitating regional or interregional solutions that more cost-effectively interconnect the renewable and storage resources needed to meet public policy goals. Because current planning methods routinely fail to consider multiple benefits across the system, they also fail to fairly allocate costs for those paying for them. Planning reactively based on individual projects will deliver fewer benefits to fewer beneficiaries at higher cost while unfairly burdening fewer parties with those costs. In contrast, planning systematically across a portfolio to meet multiple system goals over a longer time horizon can deliver substantive, diverse benefits at lower total cost to many beneficiaries across the entire region.[173] As more thoroughly discussed in the Benefits section, when transmission is evaluated on a portfolio basis considering all of the benefits, two projects together might create benefits that would not have existed if the projects were not evaluated together. FERC must adopt cost allocation rules that take into account the benefits without overburdening one set of consumers for benefits received by others.

A. State Involvement in Cost Allocation for Long-Term Regional Transmission Facilities

The NOPR proposes that to comply with this cost allocation requirement, public utility transmission providers revise their tariffs to include a cost allocation method after seeking the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission

[173] *Id*. at 4.

Planning.[174] The tariff must also include a time period for states to negotiate an alternate cost allocation method for a transmission facility selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning.[175] The NOPR explains that if the public utility transmission provider cannot get the agreement of the states, it will need to explain the good faith efforts made by it to seek agreement from such entities.[176]

In the event that the relevant state entities decline to do so, the public utility transmission providers would be required to propose a Long-Term Regional Transmission Cost Allocation Method consistent with the requirements of Order No. 1000, including the prohibition on relying on voluntary agreement among states or participant funding.[177]

FERC also preliminarily found that a State Agreement Approach, by which one or more relevant state entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or portfolio of facilities) after it is (or they are) selected in the regional transmission plan for purposes of cost allocation may be a just and reasonable approach to cost allocation for such regional transmission facilities. The NOPR made clear that any State Agreement Approach must comply with the six Order No. 1000 cost allocation principles.

At a high level, the transmission cost allocation must weigh several factors, namely: (1) a fair assignment of costs among participants that avoids free ridership by including those who cause these costs to be incurred and those who otherwise benefit from Long-Term Regional Transmission Facilities—either now or in the future—even if they do not support construction of the Facilities; (2) whether it provides adequate incentives to construct new transmission; and (3) whether the proposal is generally supported by state authorities and participants across the

[174] NOPR at P 322.
[175] *Id*. at P 323.
[176] *Id*. at P 303.
[177] *Id*. at P 307.

region. Importantly, the final cost allocation must be roughly commensurate with benefits.[178] Furthermore, a cost allocation method must be clearly established and stable over time to ensure such projects are not delayed by questions or disputes about cost allocation and successive projects and project portfolios are subject to the same processes.

PIOs support FERC's proposal to allow states an opportunity to agree on transmission cost allocation—either through an *ex-ante* cost allocation methodology or through a State Agreement Approach. As stated in the NOPR, providing state regulators with an opportunity to develop a cost allocation method for transmission facilities could help increase stakeholder—and state—support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable Commission-jurisdictional rates.[179] However, any cost allocation methodology agreed to by the states must meet the mandate that FERC "has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the assigned costs.[180]

As discussed in more detail in the section on Benefits, in the NOPR, FERC outlined a non-exhaustive set of 12 benefits of transmission that are quantifiable. In that section, we advocate that FERC mandate these as a minimum set of benefit metrics and allow transmission planners the discretion to add more. Similarly, we believe that any *ex-ante* cost allocation methodology approved by FERC must consider these quantifiable benefits.

The Brattle Report shows that many quantifiable benefits of transmission are currently being left on the table. We go into more detail above on how these benefits must be included in selecting transmission projects in the transmission planning process for the purposes of cost

[178] *See Ill. Commerce Comm'n*, 576 F.3d 470.
[179] NOPR at P 299.
[180] *Ill. Commerce Comm'n v. FERC*, 576 F.3d at 477.

allocation. The corollary to that is that the cost allocation must then follow the benefits. Having acknowledged the multiple calculable benefits of transmission, FERC and states cannot then pretend those benefits do not exist when allocating the costs of transmission.

The NOPR states that, by requiring a longer-term planning horizon, consideration of multiple scenarios, and accounting for the longer-term factors that affect transmission needs, Long-Term Regional Transmission Planning will be complex and raises a concern that such complexity could make cost allocation decisions more contentious.[181] The Commission then raises the concern that this may risk undermining the development of more efficient or cost-effective regional transmission facilities to address transmission needs driven by changes in the resource mix and demand. However, the real risk of undermining good transmission planning and cost allocation is allowing the public utility transmission providers to produce cost allocation that is not in line with court precedent. And courts have been clear that costs must roughly follow benefits.

Further, in Order No. 1000, the Commission raised the concern that "because large-scale transmission investments that geographically extend or strengthen the integration of the transmission system are both costly and tend to produce widespread benefits, there is significant risk that free ridership problems inhibit their development."[182] If the Commission allows public utility transmission providers to agree to cost allocation that does not reflect all of the quantifiable benefits of transmission, it will be re-introducing this risk of free ridership into the transmission planning process.

FERC also asks what should happen if relevant state entities cannot reach agreement on a cost allocation method. First, the Commission must define "agreement." PIOs believe that the

[181] *See* NOPR at P 289.
[182] *Id*. at P 32, *citing* Order No. 1000 at P 486.

Commission should not allow one state or a small subset of states to withhold agreement and delay cost allocation for project and portfolio execution. Therefore, FERC should not require that the states in a particular region unanimously approve a cost allocation methodology nor hold up an entire new transmission portfolio that benefits that entire region; this is particularly important for the regions without existing RTOs and ISOs that do not yet have established institutions, habits, and rules for regular coordination and agreement. Rather, the public utility transmission provider should be able to adopt a cost allocation that is otherwise just and reasonable with a majority of states' agreement. Each RTO/ISO currently has an organization of its states called a Regional State Committee ("RSC"), which allows the states to collectively provide state input on RTO/ISO proposals. In fact, most of the RSCs require a simple majority vote. For example, the SPP RSC, Organization of PJM States ("OPSI"), and Organization of MISO States ("OMS") require that a policy position be approved by a majority of the RSC Board, so long as the position identifies participating and non-participating members.[183] The OMS MISO Advisory Process further provides that "state commissions are most effective when they can speak with one voice in communications to the MISO Board and, especially, to the FERC," but acknowledges that "… this may not always be possible."[184] The New England States Committed on Electricity (NESCOE), the RSC for ISO-NE, similarly only requires the agreement of a majority of the states and there have been a few recent instances in which NESCOE has taken a

[183] Southwest Power Pool, *Regional State Committee Bylaws*, art. IV § 10 (Oct. 30, 2017), https://spp.org/documents/55129/rsc%20bylaws%202017%20final%20approved%2010.30.17.pdf; Org. of MISO States, art. IV § 8 (Sept. 13, 2012), https://www.misostates.org/images/OrgDoc/BYLAWS_OMSasAmended13September2012.pdf; Org. of PJM States, art. IV § 8 (June 18, 2013), https://opsi.us/wp-content/uploads/2018/08/OPSI-By-Laws.pdf.

[184] Org. of MISO States, *MISO Advisory Process—Role of State Commission*, at 2 (Mar. 2005), https://www.misostates.org/images/Procedures/MISOAdvisoryProcessAdoptedMar2005.pdf.

position without unanimity.[185] Thus, PIOs maintain that any agreement by the state to an *ex-ante* cost allocation methodology should not need to be unanimous.

While the non-RTO/ISO transmission planning regions do not have similar RSCs, we believe that the experience with the RTO/ISO RSCs can be extrapolated and applied to the non-RTO/ISO transmission planning regions as well. Where disputes exist related to cost allocation in non-RTO/ISO regions, or at the seams of RTO/ISO regions, the Commission could also consider using its authority to convene a joint board with affected states, which could consider the issues presented and make a decision.[186]

Nonetheless, it remains possible that states fail to reach agreement on a cost allocation approach. The Commission requests comment on the appropriate outcome in this situation.[187] PIOs believe that absent an *ex-ante* cost allocation methodology, the entire long term planning framework envisioned in this proceeding is at risk, as requiring successful negotiation of a State Agreement for each project is unwieldy and creates opportunity for free ridership or simple obstructionism. PIOs recommend that, in the case where states are unwilling or unable to reach agreement on a cost allocation approach, the Commission should require the public utility transmission providers to establish a Long-Term Regional Transmission Cost Allocation Method. Such directive would not foreclose the Commission's ability to establish the method itself, should the method presented in compliance not be just and reasonable.[188]

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[185] *See* ISO-NE & NEPOOL, *Memorandum of Understanding among ISO-New England, Inc, the New England Power Pool, and New England States Committee on Electricity, LLC*, § 2(a) (Nov. 21, 2007), https://www.iso-ne.com/static-assets/documents/regulatory/part_agree/mou_final.pdf; *See also* Comments of NESCOE on Electricity, at 3, Docket No. ER22-1528 (Apr. 21, 2022) Accession No. 20220421-5263 ("These comments represent the collective view of five of the New England states, with New Hampshire not joining this filing as noted above.").
[186] 16 U.S.C. § 824h; 18 C.F.R. § 385.1304.
[172] NOPR at P 310.
[188] *See id.* at n.515.

It should further require public utility transmission providers to show on compliance that any cost allocation methodology agreed to by the states complies with the beneficiary pays principle by showing that the methodology considers all quantifiable benefits of transmission. In addition, as discussed in more detail below, the Commission should create a default cost allocation policy that meets this same standard that public utility transmission providers must use in the event that their states cannot come to agreement.

With respect to the State Agreement Approach, PIOs are comfortable with the Commission's proposal to adopt an approach to cost allocation for new transmission projects that allows states and interconnection customers to voluntarily accept cost allocation of transmission projects that would serve a state public policy need or satisfy an interconnection customer's need for network upgrades. Under this approach the costs of transmission projects that are identified in the Long-Term Regional Transmission Planning cost allocation processes should first be allocated to customers as the primary beneficiaries.[189] Second, the Commission should allow states and/or generation interconnection customers to voluntarily accept cost allocation of the cost of alternative or expanded transmission projects compared to projects identified in the regional transmission plan's base case.

B. A Default Cost Allocation Methodology and Deadlines are Necessary to Prevent Undue Delays

The Commission seeks comment on whether it should require, instead of the reforms proposed in this section of the NOPR, public utility transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs. The NOPR noted that relevant state entities may also fail to reach agreement on a cost allocation method for all or a

[189] *Id.* at PP 75–76.

portion of Long-Term Regional Transmission Facilities and requested comments on the appropriate outcome in that situation.

The NOPR also proposes to require that public utility transmission providers establish a 90-day time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) that is different than any *ex-ante* regional cost allocation method that would otherwise apply, which the public utility transmission provider may elect to file with the Commission for consideration under FPA section 205. If the Commission rejects a state-proposed cost allocation method, the applicable *ex-ante* regional cost allocation method would apply. In addition, the Commission seeks comment on whether there should be a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes.

PIOs strongly support the Commission's proposal for the public utility transmission providers to have a hard deadline for states to agree to cost allocation and believe that no longer than 90 days is the right amount of time. However, we believe that FERC should establish a deadline for both an *ex-ante* cost allocation methodology and the State Agreement Approach. For the *ex-ante* cost allocation, that deadline may be the compliance date of the rule. If the states cannot agree by this deadline, FERC must institute a default cost allocation methodology that the region must use that allocates costs commensurate with all quantifiable benefits. Setting a default cost allocation methodology in the rule that all transmission planning entities must adopt if the states cannot agree is directly in line with the Commission's previous observation that a sense of fairness in the benefit-cost allocation process is critical:

> The Commission has previously recognized that knowing how the costs of transmission facilities would be allocated is critical to the development of new transmission infrastructure. Without such clarity, the likelihood that transmission facilities selected in a

> regional transmission plan for purposes of cost allocation will be developed is diminished, undermining the entire purpose of the regional transmission planning process, namely, the development of more efficient or cost-effective transmission facilities. Yet, identifying a cost allocation method that is perceived as fair, especially within transmission planning regions that encompass several states, remains challenging. Litigation contesting regional transmission cost allocation methods persists. Moreover, even where the cost allocation method is reasonably settled, regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders—in particular, a state regulator responsible for permitting transmission facilities—do not perceive the regional transmission facilities' value as commensurate with their costs.[190]

Without both a deadline and a default cost allocation method, transmission development could be significantly delayed by a single state, or handful of states, that neither agrees to a cost allocation methodology nor decides not to participate in the process to determine the cost allocation methodology. Without a default cost allocation methodology, necessary transmission will be held up while the stakeholders and the states either endlessly debate an *ex-ante* cost allocation process or there will be case-by-case, project-by-project litigation to assign costs. Transmission is too desperately needed for reliability and resilience to create these delays in the transmission planning process. Moreover, such project-by-project litigation wastes scarce resources of the states, the Commission, and all stakeholders.

The Commission seeks comment on when this 90-day period should begin for the State Agreement Approach. PIOs propose that it should begin when the project or portfolio of projects is selected in the regional transmission plan for purposes of cost allocation. In reality, states will be able to start discussing alternative cost allocation prior to final project selection, so 90 days post selection will be sufficient.

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[190] *Id.* at P 297.

PIOs also seek clarification of what the Commission intends in saying that "the public utility transmission provider *may elect* to file [a state-negotiated alternate cost allocation method] with the Commission for consideration under FPA section 205."[191] PIOs believe that any cost allocation method, whether *ex-ante* or State Agreement Approach, must be on file with and approved by the Commission to ensure that it is just and reasonable.

Finally, as discussed above, cost allocation should be as consistent as possible across the entirety of the transmission planning process, including existing near-term reliability and economic regional transmission planning processes. Because needs that are not resolved through Long-Term planning will ultimately be addressed in the near-term processes, inconsistent cost allocation creates incentives for states who prefer the cost allocation approach of the near-term processes to undermine long-term planning. Put differently, the existence of two distinct cost allocation methods can be unjust, unreasonable, and unduly discriminatory even when each method, taken on its own, falls within the zone of reasonableness. The existence of multiple cost allocation approaches also creates uncertainty, a factor that the Commission has identified as a barrier to transmission development.[192]

The NOPR includes a preliminary finding that failure to consider a broader set of benefits and beneficiaries of transmission facilities may result in unjust, unreasonable, unduly discriminatory, and preferential rates.[193] This necessarily implicates cost allocation, as it is difficult to see how a lawful cost allocation approach can be based on unlawful identification of benefits and beneficiaries.

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[191] *Id.* at P 319 (emphasis added).
[192] *See id.* at P 297.
[193] *Id.* at P 35.

PIOs thus respectfully request that the Commission reconsider its preliminary finding that cost allocation for Long-Term projects may differ in part from cost allocation for near-term projects[194] and that no changes be required to existing Order 1000 cost allocation.[195] Instead, PIOs recommend the Commission (1) require compliance filings to identify and justify differences between Long-Term and near-term cost allocation; (2) provide notice that it is disinclined to approve compliance filings that create opportunities for "cost allocation arbitrage"; and (3) require transmission providers to demonstrate on compliance that their current Order No. 1000 cost allocation methods are just, reasonable, and not unduly discriminatory or preferential in light of the broader set of benefits and beneficiaries to be considered, and propose replacement for any Order 1000 cost allocation rates that are not.

X. The Commission Should Require Better Coordination of Cost Allocation for Generator Interconnection and the Regional Planning Process in a Separate Rulemaking

As PIOs noted in our ANOPR Comments, the lack of cost allocation for transmission facilities necessary to interconnect new generation massively raises the cost of interconnection and keeps many otherwise economic projects from coming online.[196] This is because interconnecting customers are stuck with the full cost of these transmission facilities. Yet transmission facilities required to interconnect new generation often have benefits that go beyond the interconnecting resources.[197] The current practice of allocating costs of new transmission infrastructure associated with interconnecting generators violates settled law that requires costs to be allocated both to cost causers *and* beneficiaries. It is, therefore, crucial that the Commission

[194] *Id.* at P 299.
[195] *Id.* at n.441.
[196] *See* PIOs' Initial ANOPR Comments at 106 (showing historically high interconnection costs for wind and solar in MISO and PJM).
[197] *Id.* at 129, *citing* ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, American Council of Renewable Energy (Sept. 9, 2021) ("ACORE White Paper"), https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf.

fix the current requirements that interconnection costs are allocated only to interconnecting customers rather than to the full suite of beneficiaries as the law demands.

PIOs recognize that the Commission has published a notice of proposed rulemaking addressing generator interconnection reforms and we look forward to commenting on the proposal.[198] However, the Interconnection NOPR focuses largely on queue reforms, addressing cost allocation only to the extent that multiple generators contribute to the need for a given transmission facility for interconnection.[199] Unfortunately, the Commission has not proposed a solution concerning cost allocation of interconnection costs in this NOPR either. Instead, the Commission proposes a half-measure that requires public utility transmission providers to include in their Long-Term Regional Transmission Planning processes transmission facilities that a transmission provider has identified multiple times in the generator interconnection process but that has never been constructed due to withdrawal of the underlying interconnection requests.[200] Where transmission needs have been identified at least twice in five years and the interconnection request has been withdrawn, public utility transmission providers must include in the Long-Term Regional Transmission Planning process transmission projects that are higher than 200 kV and/or cost more than $30 million so long as the project has not been included as part of a generator interconnection agreement.[201] While this requirement will have planning benefits and should be adopted, it will not address interconnection cost issues for projects at the time they are proposed.

[198] *See* Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39,934 (July 5, 2022) ("Interconnection NOPR").
[199] *Id.* at P 88.
[200] NOPR at P 166.
[201] *Id*.

PIOs are disappointed that the Commission has so severely limited the potential for cost allocation of facilities crucial for generation interconnection, but PIOs support the Commission's limited proposal because it requires transmission planners to include in the planning process transmission projects that are significant sticking points for getting new generation interconnected. We strongly encourage the Commission to address the need for broader cost allocation of transmission facilities necessary for interconnection in a future rulemaking. The long-term planning process should look at all generation interconnection requests to see if it is possible to develop cost-effective transmission and related solutions that realize economic, reliability, interconnection, and other benefits in a comprehensive, cost-effective fashion relative to disjointed, serial interconnection lines charged to individual generators.

However, neither the NOPR under consideration in this docket nor the Interconnection NOPR fully address the issue of cost allocation of projects identified through the interconnection process that provide benefits beyond mere interconnection. As PIOs explained in our previous comments, the beneficiaries of many new transmission projects needed to allow new generators to interconnect go well beyond the interconnecting customers.[202] While this NOPR may help properly cost allocate some transmission projects that originated in the interconnection queue, it does not resolve the underlying problem that in many instances interconnecting generators are required to pay for transmission projects that have benefits well beyond merely interconnecting those generators. We urge the Commission to go beyond the steps proposed in this NOPR and the Interconnection NOPR to propose a new rulemaking specifically targeted at fixing the broken cost allocation of transmission needed for generator interconnection.

[202] *Id*. at 129, *citing* ACORE White Paper.

XI. FERC Must Create and Mandate Effective Joint Interregional Planning Requirements

As PIOs noted in our ANOPR Comments, experience has shown that, for all practical purposes, the interregional coordination process required by Order No. 1000 does not produce effective results. For many planning regions, this coordination process has essentially become a paper exercise, has failed to identify much less implement needed projects,[203] and consequently has failed to alleviate unlawful rates and practices identified by the Commission as requiring an expeditious remedy over 10 years ago—the need for which has only grown more pressing since. It is therefore not sufficient to simply reform the existing interregional *coordination* process. Rather, FERC must create and mandate effective joint interregional *planning* requirements as an integral part of a single comprehensive and holistic transmission planning process that incorporates the specified criteria mentioned above as well as mandate the implementation of the projects in those regional and interregional long-term transmission plans.

The record in this proceeding is replete with evidence that interregional transmission projects unlock the ability to maximize net consumer benefits.[204] A broad coalition of commenters agrees that eliminating existing barriers to interregional transmission planning will also improve reliability and resilience in the face of increasing extreme weather events and will maximize benefits across regions.[205] However, barriers to interregional planning make it virtually impossible to maximize net consumer benefits. These barriers to interregional planning have created a gap in investments near and across market seams as regional planning authorities

[203] PIOs' Initial ANOPR Comments at 45 (describing interregional planning process meetings in RTO/ISOs/regions).

[204] *See, e.g.*, Comments of the Electricity Consumers Resource Council (Oct. 12, 2021), Accession No. 20211012-5576; Pre-Conference Comments of Dr. David J. Hurlbut; Pre-Conference Comments of Dr. Debra Lew (Nov. 10, 2021), Accession No. 20211110-5170. *See also* The Brattle Group, *A Roadmap to Improved Interregional Transmission Planning*, at B1–B3 and App. B (Nov. 2021) (attached to PIOs' Reply ANOPR Comments as Exh. A).

[205] PIOs' Reply ANOPR Comments at 21–22.

have shifted away from development along seams with neighboring regions and instead focus primarily on local and regional investments and generator interconnection requests.[206]

The Commission's findings in the NOPR echo these concerns, pointing out that in establishing Order No. 1000, it determined that "the transmission planning requirements of Order No. 890 were too narrowly focused geographically and failed to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions."[207] Therefore, the Commission concluded that interregional transmission coordination reforms were necessary, which included "[c]lear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans."[208] Perhaps admitting that these reforms have not led to increased interregional coordination, the Commission finds in the NOPR that "there is a significant need for interregional transmission coordination" and that "it is necessary to revise the existing Order No. 1000 interregional transmission coordination requirements to apply them to the proposed Long-Term Regional Transmission Planning reforms in this NOPR to ensure that interregional transmission coordination is just and reasonable."[209]

To remedy these issues, the NOPR proposes that public utility transmission providers in neighboring transmission planning entities be required to revise their existing interregional coordination procedures (and regional transmission planning processes as needed) to require the sharing of information regarding the respective transmission needs identified in the Long-Term

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[206] *Id*. at 23–24.
[207] NOPR at P 424, citing Order No. 1000 at P 369.
[208] Order No. 1000 at P 368.
[209] NOPR at P 425.

Regional Transmission Planning process, as well as potential transmission facilities to meet those needs; and identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.[210] In addition, the NOPR proposes to require that public utility transmission providers in neighboring transmission planning entities revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.[211] However, despite industry changes since Order No. 1000, including changes in resource mix, operational challenges, and increasing regional integration, the NOPR does not propose changes to the existing interregional transmission coordination and cost allocation requirements of Order No. 1000.

With respect to coordinated interregional transmission planning and cost allocation, the reforms proposed in the NOPR would require that public utility transmission providers revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms. PIOs believe that requiring identification of interregional projects through the regional transmission planning process is a good start, but that this requirement should be a bare minimum. A separate rulemaking will be needed on interregional transmission planning and cost allocation. PIOs urge the Commission to start such a proceeding as soon as possible to ensure that the grid evolves in an integrated, beneficial, and flexible manner across seams instead of as a patchwork of local and regional facilities.

[210] *Id*. at P 427.
[211] *Id*. at P 428.

The Commission should anticipate the difficulties of aligning the interests of a large number of stakeholders and balancing the economic, public policy, and other factors that bear on grid integration. As PIOs have mentioned in these comments as well as our ANOPR Comments, robust, forward-looking, proactive planning must necessarily be based on the best available data and realistic scenarios of future technological, demand, and economic conditions. The data used and the scenarios and benefits considered must be consistent across regions and across planning processes such that it plans so that participants can work on planning processes and compare results seamlessly. If this collaborative planning process is to reach timely and executable outcomes, the Commission needs to establish boundaries around the timing of processes and the latitude afforded the participating states and stakeholders, including the development of planning rules and practices.

For example, the planning process must consider and then adopt plans to build projects that maximize the broadest array of benefits for the broadest number of markets and consumers. PIOs recommend mandatory joint planning across regions and the use of transmission network portfolios to address diverse system needs more efficiently than a project-by-project approach. In all cases, FERC should require interregional planning to employ common assumptions, methods, and timelines for action as well as uniform modeling approaches. In addition, by mandating that all transmission planning entities assess the same benefits, as PIOs advocate above, adjoining regions will be able to evaluate an interregional transmission project on an even playing field, avoiding the current problem where any interregional line would need to go through at least two separate regional transmission planning processes, with different underlying assumptions and benefits calculations, in addition to an interregional coordination process—the so-called "triple hurdle." Transparent procedures will minimize the potential for any one state or stakeholder to essentially veto consideration of a multi-state project for cost allocation. FERC must retain authority to act as the default decision maker if an impasse is reached.

Other proactive options include establishing a separate interregional planning body, perhaps comprised of RTO/ISO personnel and/or market monitors, which would have responsibility for developing long-term plans, cost allocation for interregional projects, and for negotiating with states for standardized siting rules for interregional projects.[212] FERC should particularly consider solutions to greater difficulties of coordination within non-RTO/ISO regions and between non-RTO/ISO regions and RTO/ISO regions. FERC should encourage and support more broadly scoped regional planning exercises in non-RTO/ISO regions and at seams with RTO/ISOs, including through partnership with NARUC, existing reliability and coordinating bodies in those regions, and the Department of Energy and the National Laboratories.

Joint interregional planning should include some consideration of conforming state siting and permitting regimes in the interest of accelerating grid integration. Proactive regional and interregional planning that incorporates state input should identify the actual or potential availability of publicly owned rights of way (e.g., highways), existing transmission rights of way, and existing longitudinal private rights of way (e.g., railroads). Coordination with DOE's refreshed approach to National Interest Electric Transmission Corridors will be especially important to mapping multi-state, multi-market transmission expansions like a macro-grid and should not await completion of the Long-Term Regional Transmission Planning in particular cases.

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[212] Initial PIO ANOPR Comments at 69–72.

XII. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements

In Order No. 1000, the Commission eliminated provisions in Commission-jurisdictional tariffs and agreements that established a federal ROFR for an incumbent transmission provider with respect to entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation.[213] This in principle enabled competition for the provision of new transmission facilities. Over the years, the Commission has also approved multiple exemptions to its removal of the ROFR, including for local transmission facilities,[214] upgrades to a transmission owners' own existing transmission facilities,[215] use and control of its existing rights-of-way under state law,[216] and immediate need reliability projects.[217]

Order No. 1000 removed the federal ROFR for multiple reasons, among them that the federal ROFR "creat[ed] a barrier to entry," and could lead to the loss of nonincumbent transmission developer investment opportunities to incumbent public utility transmission

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[213] Order No. 1000 at P 313; Order No. 1000-A, 139 FERC ¶ 61,132 at P 426 (May 17, 2012) ("Order No. 1000-A") ("The concept is that there should not be a federally established monopoly over the development of an entirely new transmission facility that is selected in a regional transmission plan for purposes of cost allocation to others."). The phrase "a federal right of first refusal" refers only to rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Order No. 1000-A at P 415. Before Order No. 1000, some RTO/ISO governing documents and other utility tariffs and agreements included federal rights of first refusal, which "gave incumbent utilities the option to construct any new transmission facilities in their particular service areas, even if the proposal for new construction came from a third party." *S.C. Pub. Serv. Auth. v. F.E.R.C.* 762 F.3d 41, 72 (D.C. Cir. 2014).

[214] Order No. 1000 at PP 63, 226, 258, 318. In addition, the Commission clarified in Order No. 1000-A that a transmission facility whose costs are 100% allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is located is not considered to be selected in the regional transmission plan for purposes of cost allocation and could remain subject to a federal ROFR. Order No. 1000-A at PP 423–424; *see also id.* at P 427.

[215] Order No. 1000 at PP 226, 319; Order No. 1000-A at P 426. Upgrades to existing transmission facilities include, for example, tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. Order No. 1000 at P 319. The Commission clarified in Order No. 1000-A that the term "upgrade" means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term does not refer to an entirely new transmission facility. Order No. 1000-A at P 426.

[216] Order No. 1000 at PP 226, 319.

[217] *See, e.g.*, *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,117, at P 3 (2021); *Sw. Power Pool, Inc.*, 171 FERC ¶ 61,213, at P 3 (2020); *Midcontinent Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,203, at P 1 (2020); *ISO New Eng. Inc.*, 171 FERC ¶ 61,211, at PP 1, 3 (2020); *N.Y. Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,082, at PP 30–34 (2020).

providers, which "discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level" in regional transmission planning processes.[218] The Commission also found that federal rights of first refusal "may result in the failure to consider more efficient or cost-effective solutions to regional needs" and thus their elimination may give "customers . . . the benefits of competition in transmission development and associated potential savings."[219] The Commission also expressed concern that federal rights of first refusal could allow an incumbent transmission provider "to act in its own economic self-interest," which in general would not support permitting "new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs."[220]

In the NOPR, the Commission proposes to amend Order No. 1000's nonincumbent transmission developer requirements to allow the exercise of federal ROFR for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider establishing joint ownership of the transmission facilities with unaffiliated nonincumbent transmission developers as defined in Order No. 1000,[221] or another unaffiliated entity, including another incumbent transmission provider. To justify this return to a limited NOPR, FERC states that "the degree to which competitive transmission development processes have led to specific transmission facility selection, investment, and development activities since Order No. 1000—and the proportion of such processes that resulted in the selection of a nonincumbent transmission developer's proposal—varies significantly by

[218] NOPR at P 340, citing Order No. 1000 at PP 229, 256–257, 284, 320.
[219] Order No. 1000 at PP 284–286, 291
[220] *Id*. at P 256.
[221] *See* NOPR at 358.

region."[222] As noted in PIOs' ANOPR Comments,[223] the Commission finds a connection between a lack of a federal ROFR and the current lack of regional transmission projects:

> As noted above, recent investment appears to be concentrated in transmission facilities not subject to Order No. 1000 competitive transmission development processes, which are often developed within individual incumbent transmission provider retail distribution service territories or footprints or address narrow regional transmission needs, as opposed to investment in regional transmission facilities selected in a regional transmission plan for purposes of cost allocation that serve a wider set of transmission needs and are subject to competitive transmission development processes.[224]

FERC posits that its elimination of the federal ROFR:

> …may in fact be inadvertently discouraging investment in and development of regional transmission facilities to some extent. Incumbent transmission providers, as a result of those reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint.[225]

FERC proposes to remove this perverse incentive for incumbent transmission providers to focus their investments on local projects that provide fewer benefits to the system by allowing the exercise of a federal ROFR for transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission tempers its shift back toward a federal ROFR by providing a presumption of just and reasonable rates and a lack of undue discrimination only

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[222] NOPR at P 343, citing FERC, *2017 Transmission Metrics*, at 23–26 (Oct. 6, 2017), https://www ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf; *see also* Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, LSP Transmission Holdings, LLC, at 5, 8 fig. 2, 28 fig. 10 (Apr. 2019) (Comments of LS Power Grid, LLC in Response to the Commission's Advanced Notice of Proposed Rule Making, Exh. 2 (Oct. 12, 2021), Accession No. 20211012-5696.
[223] PIOs' Initial ANOPR Comments at 31.
[224] NOPR at P 349.
[225] *Id.* at P 350.

if the exercise of the ROFR is conditioned on joint ownership of the transmission facilities with an unaffiliated entity.

PIOs support the goals of competition for transmission development. As noted in Order No. 1000, competition encourages the consideration of alternative, creative transmission solutions and the consideration of more efficient or cost-effective solutions to regional needs. These in turn result in potential savings for customers.[226] As discussed elsewhere in these comments, in determining which proposed transmission project is chosen through the regional transmission planning process for the purposes of cost allocation, the Commission should require the calculation of all calculable benefits in addition to the total cost of the project. This can help bring forward projects that realize the wide array of benefits that any given transmission project can provide to the system.

While the Commission has preliminarily chosen to reinstate a limited federal ROFR, we note that the Commission has a variety of tools available to address unintended consequences of Order No. 1000's removal of the federal ROFR to incentivize local projects over regional projects. Rather than reduce competition, the Commission could, as many commentors have suggested previously, attempt to fix the misaligned incentives by expanding rather than retracting competition requirements.

If the Commission chooses to move forward with reinstating a limited federal ROFR, it must take steps—as outlined below—to ensure that the transmission planned through the process—including any transmission that is afforded a ROFR—is an efficient and cost-effective solution to regional needs or is truly needed only for local needs. The Commission should also take necessary steps to ensure that the lack of competition does not stifle creativity.

[226] Order No. 1000 at P 284–285.

FERC should be cognizant of the unintended consequences of any re-introduction of the federal ROFR. For example, the adoption of a limited federal ROFR could unintentionally incentivize utilities to propose transmission wholly within their own service territories to take advantage of the ROFR, even when the most efficient and cost-effective transmission solution, and one that would provide multiple regional benefits, would span multiple utility territories. As discussed throughout these comments, regional lines—and especially portfolios of regional lines—are crucial for the buildout of much needed transmission infrastructure. If incumbent utilities have an incentive to keep lines solely within their service territories, this could have the unintended consequence of continuing to balkanize the transmission system through piecemeal development, resulting in higher costs for customers. If FERC chooses to adopt a limited ROFR, it must ensure that transmission planning entities engage in truly holistic planning that would not inadvertently result in this kind of piecemeal planning. The Commission should treat its new limited ROFR as just that: a ROFR. If the regional transmission plan produces an efficient and cost-effective solution within an incumbent's service territory, that could be subject to the limited ROFR, but if the incumbent for whatever reason does not want to construct the more effective and cost-efficient solution, the project should be offered to other transmission developers. Ratepayers should not lose access to more efficient or cost-effective solutions solely to allow the exercise of ROFR. FERC should also ensure that the transmission planning entities consider advanced technologies and alternatives that produce cost effective solutions to transmission needs. PIOs acknowledge that the Commission has announced a technical conference for October 6, 2022, to discuss the cost effectiveness of local and regional transmission planning decisions.[227] This will include a discussion of "how public utility

[227] FERC, *Transmission Planning and Cost Management; Notice of Technical Conference*, Docket No. AD22-8-000 (Apr. 21, 2022).

transmission providers identify transmission projects in local and regional reliability transmission planning processes" and "a role for an independent transmission monitor." While we look forward to a robust discussion of these issues, FERC can still take action in this proceeding to ensure cost effective transmission is chosen through the transmission planning process by requiring more holistic planning.

The NOPR does not provide any rules or guidance on whether the limited federal ROFR will apply where the incumbent utility seeks to build a project in a state or states that prefer competition for transmission facilities. Today, some states implement state ROFRs for incumbent transmission providers. The Commission does not forbid these state ROFRs. Similarly, the Commission should not impose a limited federal ROFR on states that prefer competition.[228]

Further, if FERC adopts a limited federal ROFR, it will be important to have sufficient oversight of the transmission planning processes by either an appropriately staffed FERC office or Independent Transmission Monitors to ensure that the process produces efficient and cost-effective transmission plans. As PIOs stated in our Initial ANOPR Comments, the Commission should give great weight to independent evaluation of transmission projects such as a review carried out by an independent regional planning body, an RTO/ISO, or a hypothetical Independent Transmission Monitor. Conversely, the Commission should take a dim view of approving cost recovery for investments that are not susceptible to review.[229] This is particularly true for any project that is selected pursuant to a ROFR given that such projects, by definition, do

[228] For example, the New Jersey Board of Public Utilities and PJM Interconnection have received 80 different proposals for offshore wind transmission solutions through solicitation launched last year. *See* New Jersey Board of Public Utilities, *New Jersey Updates Schedule for Third Offshore Wind Solicitation* (Feb. 28, 2022), https://www.nj.gov/bpu/newsroom/2022/approved/20220228 html.
[229] PIOs' Initial ANOPR Comments at 62.

not go through any independent review. Therefore, there should be increased scrutiny over such projects to ensure that they provide the benefits they purport to at the costs they assert.

Finally, if the Commission adopts a limited federal ROFR, it should reiterate that all requirements for benefit-to-cost ratios and/or net benefits tests will still apply to projects seeking cost allocation. As discussed throughout this process, removing competition from the regional transmission planning process removes an important check on project costs. Without the downward pressure on costs of competition, incumbent utilities have the incentive and opportunity to drive up project costs in order to receive a greater return on investment. One important check on these increased costs is to maintain standards around benefit-to-cost ratios and net benefits tests to ensure that projects are creating more benefits than costs.

XIII. Issues, Challenges, and Recommendations Specific to the Western Interconnection and Associated Regions

The Western Interconnection is composed of three Western Planning Regions: WestConnect, Northern Grid, and CAISO. The Western Interconnection is unique in that it is composed of both an ISO (CAISO) and a very large geographic area comprised of two Western Planning Regions (WestConnect and Northern Grid) operating in a bi-lateral market. The geography and grid operation of the West present challenges that necessitate special consideration by FERC to help the West optimize transmission planning going forward.

Each of the three Western Planning Regions interacts with the Western Electric Coordinating Council ("WECC") for various reasons. Primarily as the reliability assurer in the West, WECC offers the collection, compilation, and release of "base cases" for varying timeframes of power flow modeling as per the NERC Transmission Planning compliance requirements. These datasets are then used by each utility and/or regional planning group to do transmission expansion assessments or system stability for reliability tests.

The Anchor Data Set ("ADS") is intended to be a compilation of load, resource and transmission topology information used by the Western Planning Regions in the Western Interconnection as part of their regional transmission plans. The ADS can also be used by other stakeholders in various planning analyses. WECC develops and manages the ADS process in partnership with the Western Planning Regions and International Planning Regions. Data included in the ADS is intended to be compatible with Production Cost Models (PCM) and power flow models, including dynamic data and associated assumptions. The data is expected to reflect applicable state and federal public policy requirements, such as: Renewable Portfolio Standard, Regional Haze Programs,[230] and Mercury and Air Toxic Standards.[231] The ADS is comprised of data developed by Data Submitters, defined as NERC Registered Entities (which include Balancing Authorities, Transmission Planners and/or Planning Coordinators) in the U.S. and by other entities in Canada and Mexico, or their designees. The ADS will reflect the Western Planning Region and International Planning Region view of loads, resources, and transmission topology for a ten-year planning horizon. The ADS provides a dataset that is intended to be a common starting point for Western Planning Regions. It may be used by WECC and stakeholders to conduct PCM studies and coordinated PF/dynamic studies.

Whenever there is a change in the base cases by any regional planning group, these changes (i.e., modeling assumptions on generation or transmission levels) are typically not provided to WECC staff. If any Western Planning Region is not satisfied with the latest WECC dataset, customized changes are made to suit the specific planning groups' needs, which results in occasional use of an outdated and/or previous year's dataset by the specific regional planning

[230] *See* U.S. Env't Prot. Agency, *Regional Haze Program* (Mar. 8, 2022), https://www.epa.gov/visibility/visibility-regional-haze-program.
[231] *See* U.S. Env't Prot. Agency, *Mercury and Air Toxics Standards* (Feb. 1, 2022), https://www.epa.gov/mats.

group. Such an inconsistency in starting point in terms of the power flow or production cost dataset can result in different interpretations of the Order No. 1000 submitted plans, even if consistent scenarios are modeled.

For various reasons—data sharing challenges or lack of agreed coordination on data updates between WECC staff and the Western Planning Region—there is a disconnect in terms of the data used by the Western Planning Region entities or the validity of the data for the Western Planning Region entities to conduct defensible and robust regional planning in the West. This has resulted in inconsistent use of WECC ADS starting point datasets and a diversity of transmission planning projections across the Western Planning Regions.

In light of all these challenges, PIOs offer the following recommendations that would enhance the role of WECC with Western Planning Regions and facilitate a real interconnection-wide planning process and oversight:

1. *Explicit coordination between Western Planning Region entities and WECC*: The original intention and vision of the ADS was to coordinate and leverage WECC data collection processes to inform Western Planning Region requirements for planning under FERC Order No. 1000 requirements. That coordination and relevant updating of data assumptions for TPL studies and related Base Case buildout is not consistent. PIOs recommend an explicit planning guideline from FERC that would call upon the Western Planning Region entities in the Western Interconnection to leverage the ADS process effectively and notify WECC staff of any changes in their specific modeling cases that can inform the future updates of the WECC power flow and production cost modeling assumptions, including current generation and transmission topology details. This would ideally also include projected future generation and transmission expansion

projections and potential expansion to comply with clean energy policies or public policy mandates of Western states.

2. *Consistent updating between Western Planning Region and WECC Staff on ADS data and changes*: PIOs recommend that WECC staff and Western Planning Regions establish a memorandum of understanding or a data updating policy that provides a regular check-in and updating of any power flow or production cost data assumptions to be updated.

3. *Coordination between WECC Reliability Assessment Committee (RAC) and Western Planning Regions on planning scenarios*: The WECC Scenarios Work Group (SWG) is principally focused on developing year-20 scenarios that reflect reliability risks associated with changing resource mix, technology investments and decarbonization trends and retirements of generation facilities. The Western Planning Regions are expected to conduct transmission planning that includes forecasted changes to their system and footprint with similar drivers and trends. However, it is unclear if there is explicit coordination between WECC and Western Planning Regions to ensure similar scenario classifications are leveraged, even if the inputted data or modeling assumptions vary by each Western Planning Region. PIOs recommend an explicit coordination for Western Planning Region entities to consider the WECC scenarios in their assessment for year-10 impact assessment for reliability, public policy considerations and economics.

4. *Establishment of an Independent Planning Monitor (IPM) role for WECC*: In the Western Interconnection, where a majority of the western utilities do not participate in an RTO/ISO, it is imperative for the Western Planning Region entities to have some form of oversight. PIOs recommend the establishment of an Independent Planning Monitor function for WECC. The IPM role should be structured to not compromise WECC obligations under Section

215 of the Energy Policy Act. Specifically, PIOs recommend that that FERC establish an IPM entity that in essence would ensure consistency of data use, coordination between Western Planning Region, WECC, and FERC as needed and a framework for ease of interregional planning.[232] It is feasible for WECC to take on the role of IPM in the West given that it has an independent board and existing relationships with member utilities, public interest and consumer advocate entities, western states' regulators. IPM authority vested with WECC would ensure that consistency of data sharing and standard processes for modeling future trends of transmission are reflected in scenarios used by Western Planning Region entities and also considered by WECC, which will be "interconnection-wide" and not project specific.

XIV. Conclusion

PIOs appreciate the opportunity to provide these comments on the Commission's timely and important NOPR and ask that the Commission consider the recommendations made herein in this rulemaking.

Dated: August 17, 2022

Respectfully submitted,

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[232] *See* Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms,* at 16 (July 2022), https://www.raponline.org/wp-content/uploads/2022/07/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf.

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CERTIFICATE OF SERVICE

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

Dated this 17th day of August, 2022.

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EXHIBIT A

AFFIDAVIT OF JOHANNES P. PFEIFENBERGER ON BEHALF OF THE NATURAL RESOURCES DEFENSE COUNCIL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF JOHANNES P. PFEIFENBERGER
ON BEHALF OF THE NATURAL RESOURCES DEFENSE COUNCIL

1. My name is Johannes P. Pfeifenberger. I am a Principal at The Brattle Group, an economic consulting firm with offices in Boston, Chicago, New York, San Francisco, Washington DC, Brussels, London, Madrid, Rome, Sydney, Toronto, Beijing, and Shanghai. I am also a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), a Senior Member of the Institute for Electrical and Electronics Engineers (IEEE), and an advisor to several transmission study efforts by the Energy System Integration Group (ESIG), the U.S. Department of Energy, and National Laboratories.

2. I am an economist with a background in electrical engineering and more than 25 years of experience in transmission and wholesale electricity markets in North America. My expertise includes wholesale power market design and transmission planning, pricing, and cost-benefit analyses. I am the author or co-author of numerous reports on transmission planning and frequently present on transmission-related matter at industry events and before regulatory agencies, including the Federal Energy Regulatory Commission ("FERC" or "Commission"). Some of this work is referenced in the Commission's April 21, 2022 Notice of Proposed Rulemaking on transmission planning (the "Transmission Planning NOPR" or "NOPR").[1] My experience, including transmission-related expertise, is summarized more fully in Attachment A.

3. I have been retained by Natural Resources Defense Council to offer comments on the Transmission Planning NOPR. Specifically, I have been retained to provide expert testimony

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1 *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

with regard to proactive, multi-value transmission planning and the list of benefits proposed in the notice.

4. My affidavit covers the following points:

   a. I confirm that the list of transmission benefits proposed in the NOPR is sound and should be considered in all transmission planning efforts;

   b. I explain why quantifying this list of benefits, if implemented correctly, does not double count transmission-related values;

   c. I explain that, if quantified "transmission benefits" exceed transmission project cost, this translates into lower system-wide electricity cost for electricity customers;

   d. I explain why the proposal to require advanced transmission technologies to be considered as part of the transmission planning process will increase the cost-effectiveness of the existing grid and new transmission additions.

   e. I recommend that two distinct timeframes should be applied to the determination of long-term transmission needs and the comparison of transmission benefits and costs;

   f. I explain why long-term transmission planning should be focused on portfolios of transmission projects that address the broad range of future needs;

   g. I explain how proactive, scenario-based, multi-value planning should be used to mitigate risk and create insurance value to avoid high-cost outcomes; I recommend the additional requirement that the evaluation of generation interconnection needs be more integrated and coordinated with transmission planning; and

   I also recommend that the Commission require that new proactive, scenario-based, long-term planning processes be integrated and coordinated with existing (near-term) transmission planning processes such that the most cost-effective transmission solutions can actually be implemented.

1. The List of Transmission Benefits Proposed in the NOPR is Sound and Should be Considered in all Transmission Planning Efforts

5. The Transmission Planning NOPR proposes (but does not require) that planners consider quantifying twelve distinct transmission-related benefits for the purpose of identifying the

most cost effective transmission solutions and informing cost allocation.[2] The proposed set of twelve benefits includes: (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.

6. This is a sound list of transmission-related benefits as they are based on industry experience and significant efforts by Regional Transmission Organizations ("RTOs") and their stakeholders over the last decade to understand transmission-related benefits and develop quantitative approaches to estimate the individual benefits.[3] The NOPR's proposed list of benefits and methods of quantifying them have been thoroughly vetted by RTO stakeholders, RTO boards, as well as state commissions, when permitting economic and public policy transmission projects. A significant number of transmission projects and their cost allocations have been approved by RTO boards and state regulators based on this list of transmission benefits over the course of the last decade.

7. For example, as the Southwest Power Pool ("SPP") noted in its 2016 transmission benefits assessment,[4] it relied on a Metrics Task Force ("MTF"), which developed a comprehensive list of metrics by collecting ideas based on existing metrics from other RTOs—including Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection LLC ("PJM"), the New York Independent System Operator ("NYISO"), as well as the Electric Reliability Council of Texas ("ERCOT"), member companies, and industry experience. Through this process, the SPP MTF:

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2 NOPR at P 185.

3 See, *e.g.*, summary of RTO planning process benefit metrics as summarized on slide 16 of *21st Century Transmission Planning: Benefits Quantification and Cost Allocation*, Prepared for the NARUC members of the Joint Federal-State Task Force on Electric Transmission, January 19, 2022. Available at: https://www.brattle.com/insights-events/publications/21st-century-transmission-planning-benefits-quantification-and-cost-allocation/

4 SPP Regional Cost Allocation Review (RCAR II) July 11, 2016. Available at: https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

> …identified five (5) metrics that are currently used by SPP in the [Integrated Transmission Planning] process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review, and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.
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> The most important aspect of the metrics to be developed is that the metrics should be able to provide "hard dollar" impacts of transmission to rate payers. In terms of this report, "hard dollar" means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed….[5]

8. The benefit metrics proposed by the Commission have reliably demonstrated the ability to accurately quantify proposed project benefits (or lack thereof). Accordingly, given the significant and widespread experience with this list of benefits and the quantitative methods used to estimate them, as well as the need to accurately determine the potential benefits of any transmission project in order to compare with project costs, assessing the presence or absence of the benefits on this list should be mandatory for all transmission planners.

9. The requirement that the full set of benefits should be considered and evaluated does not mean that all of these benefits should be quantified for every project or portfolio of projects. Because not every benefit on the proposed list will be relevant for every project analyzed, I recommend that the Commission require a two-step process through which (1) transmission planners *qualitatively assess* the entire set of benefits when evaluating transmission solutions to long-term regional needs and (2) quantify only those benefits that are determined to apply to the specific projects analyzed. By starting with a qualitative screening of the list of benefits, this two-step process means that planners would avoid the need to numerically quantify the full set of benefits for every transmission project (or portfolio of projects) where specific transmission solutions do not offer those benefits or if those benefits would likely be too small to affect the planning decision. This approach of quantifying benefits directly relevant

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[5] SPP MTF, *Benefits for the 2013 Reg'l Cost Allocation Rev.* 10 (Sept., 13 2012) at: https://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf ("2013 MTF Cost Allocation").

to the evaluation of specific projects (or portfolio of projects) and qualitatively considering other benefits has been used successfully by a number of RTOs.[6]

2. Quantifying the Proposed List of Benefits does not Double-Count Transmission-Related Values

10. If the quantification of benefits is implemented with care, the proposed set of twelve transmission benefits represents a distinct, non-overlapping set of benefits that does not double-count any of the identified benefits. But care must be applied to avoid inadvertent double-counting of some benefits categories.

11. For example, "production cost savings" is a metric that is generally based on the economic simulation of future years, considering future market conditions for all 8760 hours of the year. Because the future conditions typically simulated in these models are based on *normalized* monthly loads without considering transmission outage or challenging conditions (such as heat waves or cold snaps) and do not consider transmission outages or the changes in transmission losses, the production cost savings metric (Item No. 3) does *not* double-count items Nos. 4 through 7 in the above list. If the simulations are improved to include some of these other items (such as transmission outages or challenging weather events that can occur in every long-term scenario of future market conditions), the production cost savings metrics will already include those other benefits.[7]

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[6] See *e.g.*, *id.* at 12–13; MISO LRTP Workshop, *LRTP Tranche 1 Portfolio Detailed Bus. Case Dev.* 10, 13-54 (Rev. Apr. 1, 2022) *at* https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623731.pdf.

[7] Note that if scenarios represent plausible distinct futures, it is important to identify which of the variables that can lead to challenging market conditions are expected to occur in every one of these futures. Cold snaps and heat waves are such an example. Because many models utilized for benefit-cost analyses (*e.g.*, nodal market and production-cost models that simulate all 8760 hours of a year) rely on normalized loads, normalized fuel prices, and normalized other market conditions, it would be reasonable to add a typical number of weeks with heat waves and cold snaps (with associated spikes in loads, fuel costs, and plant outages) to every year and every scenario simulated.

As a recent Berkeley Lab report shows, challenging market conditions have happened almost every year in the last decade. Importantly, the most challenging 5% of all hours in a year account on average for 50% of the congestion relief (production cost savings) value of transmission links. It is thus important to include such challenging market conditions in every year and future simulated (not just some individual scenarios). *See* Dev Millstein, *et al.*, *Empirical Estimates of Transmission Value Using Locational Marginal Prices*, Berkley Lab Energy Tech. Area, (Aug. 2022), *available at*: https://emp.lbl.gov/publications/empirical-estimates-transmission

12. Similarly, as already recognized in the description of the proposed benefits category No. 2, which counts either the resource adequacy cost savings of transmission investments that reduce planning reserve margins, or the benefits of a reduced loss of load probability, but not both. Thus, the benefit quantification should not count both cost savings due to reduced planning reserve margin and the reduction in loss of load probability that an RTO and its customers would realize if the planning reserve margins were not reduced in response to transmission investments' resource adequacy benefits.

13. Avoiding double-counting of possibly overlapping benefits categories has been a specific objective in the development of most RTOs' multi-value benefit framework. For example, the SPP MTF specifically and successfully developed its list and definitions of transmission benefits metrics "to ensure open and transparent communication of each metric's purpose and the elimination of any 'double-counting' that might occur when calculating the benefit of transmission project(s) or portfolio(s)."[8]

3. Transmission Benefits that Exceed Transmission Project Costs Will Lower System-Wide Electricity Costs for Electricity Customers

14. Transmission benefit-cost analyses are sometimes viewed with suspicion due to a lack of understanding of what "transmission benefits" are. While transmission project costs and their impacts on electricity customers are understood very clearly (*i.e.*, higher transmission project costs mean higher transmission rates for customer), the same cannot be said of "transmission benefits." Often it is not understood what these benefits are, who captures these benefits, and/or how they would affect electricity customers.

15. If transmission planning were part of an enhanced integrated resource planning effort that attempted to find the least-cost combination of generation and transmission investments across the system, such a co-optimized generation and transmission planning process would not need to quantify "transmission benefits" explicitly. It would simply identify the combined generation and transmission solutions that result in the lowest total costs to electricity customers. The benefit of finding such "least cost" solutions is generally well understood.

More infrequent market conditions (such as challenges that occur only once in a decade) should also be evaluated for every long-term future (even if the frequency of such events may be higher in some futures than others). These can be simulated as a sensitivity to the future years simulated.

[8] 2013 MTF Cost Allocation at 5.

16. If transmission planning is undertaken separately from the planning of generating resources—such as by independent transmission planners or the through utilities' traditional integrated planning processes (IRPs)[9]—a properly defined transmission benefit-cost framework replicates the results of the vertically-integrated planning that co-optimizes transmission and generation investments. To do so, the transmission benefits of a particular transmission project (or portfolio of projects) are measured as the reductions in "other costs" (such as generation costs and outage costs) that electricity customers face. If the reduction in these other costs exceeds the cost of the transmission investments, making the investments will reduce the total costs faced by electricity customers. In other words, if transmission investments offer a benefit-cost ratio above one (*i.e.*, transmission benefits in excess of project costs), the investments will reduce the total system-wide costs faced by electricity customers (*i.e.*, the sum of transmission costs and other costs will decline).

17. For example, assume that a transmission project with a cost of $100 million offers the following benefits: (a) it eliminates a $60 million transmission upgrade that (in the absence of the project) would be needed to maintain reliability or replace an aging existing transmission line; (b) it reduces transmission congestion that allows for the dispatch of lower-costs generation, which is projected to save $70 million in system-wide fuel costs (that are passed through to the electricity customers); and (c) it allows the construction of a generating plant in a location that reduces the generation investment costs needed to serve electricity customers by $80 million. In this case, total transmission benefits are $210 million ($60 + 70 + 80 million) and they exceed the $100 million project costs. In other words, spending $100 million on transmission saves customers $210 million in "other costs" that consumers would have to pay, such that the total costs faced by electricity customers are reduced by $110 million—equal to the "net benefits" of the transmission project. The project's benefit-cost ratio is 2.1 (*i.e.*, $210 million benefits divided by the $100 million cost). As different transmission solutions that can address identified needs are evaluated, the solution with the largest net benefits will offer customers a least-cost outcome.

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9 IRPs of vertically-integrated utilities are usually focused exclusively on optimizing generation investments; transmission is not typically part of the (mostly single-zone) models that are used to developed least-cost generation expansion and retirement plans. Unless generation and transmission is proactively co-optimized in integrated-resources planning, long-term multi-value transmission planning will be just as relevant for vertically-integrated utilities and non-RTO areas as it is for RTO regions with unbundled regional transmission planning.

18. I note that every one of the twelve transmission benefit metrics proposed in the Transmission Planning NOPR for the evaluation of specific transmission investments reflects a reduction in "other costs" faced by electricity customers. Item No. 1 reflects the costs of other transmission projects avoided by the proposed investment. Item No. 2 reflects generation investment cost savings associated with a reduced planning reserve margin (or the reduction of customer reliability-related costs, in the alternative). Items 3–7 relate to generation production cost savings under the range of normal and challenging system conditions. Items 8–10 relate to generation investment cost savings facilitated by the transmission investment (net of any such savings that would be achieved by the avoided transmission projects). And items Nos. 11 and 12 relate to market efficiency benefits that similarly translate to savings for electricity customers.

19. Thus, if the sum of these transmission benefits exceeds the cost of the evaluated transmission projects *(i.e.*, the projects' benefit-cost ratio exceeds 1.0), it means that cost savings associated with the transmission investment exceed project costs. While transmission costs increase, the total system-wide costs faced by electricity customers decrease. Given that generation-related costs in customer bills tend to substantially exceed transmission-related costs, it is critically important to evaluate (as is done through a number of the proposed benefit metrics) the extent to which transmission investments can reduce generation related investment and operating costs.

4. Considering Advanced Transmission Technologies in Transmission Planning Will Increase the Cost-Effectiveness of the Existing Grid and Enhance the Value of New Transmission Investments

20. I concur with the Commission's proposal to require that advanced transmission technologies, such as dynamic line ratings ("DLR") and advanced power flow control devices, be actively considered in regional transmission planning processes.[10] In fact, I recommend that the requirement be expanded to other advanced technologies—such as topology optimization, high-voltage direct current ("HVDC") transmission, and storage—since they all can enhance the capability of the existing grid and increase the value of new multi-value transmission investment from reliability, market efficiency, and public policy perspectives.

[10] NOPR at P 272.

21. This requirement is an important policy tool to help the industry overcome its hesitation to adopt advanced technology in both grid planning and operations. While some transmission planners may argue that dynamic line ratings and advance power flow control devices should be considered only for short-term horizon planning solutions [because] "[p]lanners cannot use DLR as a long-term planning solution to solve reliability criteria violations,"[11] this perspective misses that long-term planning should focus on a wide range of transmission needs beyond those defined solely by existing reliability planning criteria. For example, even if DLR may not be able to address certain reliability needs (*e.g.*, during summer peak conditions), the long-term planning effort should consider market efficiency and public policy benefits of the technology—such as relieving future congestion and creating "energy headroom" for renewable generation during most hours of a year. DLR can substantially increase the amount of renewable energy that can be integrated and, thus, enhance the capability of the existing grid as well as increase the cost-effectiveness of new multi-value transmission projects that are being evaluated through the new long-term regional planning process.

22. Other advanced technologies (power flow control devices, topology optimization, HVDC lines, storage, *etc*.) can certainly address long-term reliability needs—as utilities have done for decades with technologies such as reactors and phase shifters. Again, these technologies not only increase the effective transfer capability of the existing grid (by shifting flows from congested elements to portions of the grid with sufficient capacity) but they can also increase the transfer capability that new transmission investments can add to the grid. They consequently make new transmission more valuable and cost effective.

23. In an effort to help overcome industry inertia and misconceptions about the multi-value benefit of these technologies, I recommend that the Commission require that they be actively considered in both existing and long-term transmission planning processes. Such a requirement would be similar to that in the New York Public Service Commission's recent orders requiring that the state's utilities consider advanced technologies in their local

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[11] PJM Long-Term Transmission Planning Reform Workshop, *Notice of Proposed Rulemaking: Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation and Generator Interconnection Docket No. RM21-17*, 9 (Aug. 9, 2022) *at* https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220809-special/item-03---ltrtp-workshop-nopr-response.ashx.

transmission and distribution planning efforts and deploy such technologies where cost effective.[12]

5. Different Time-frames Should be Applied to the Evaluation of Long-Term Transmission Needs and the Comparison of Transmission Benefits and Costs

24. The Transmission Planning NOPR proposes that planners "use a transmission planning horizon no less than 20 years into the future in developing Long-Term Scenarios"[13] and "evaluate the benefits of regional transmission facilities to meet [identified] needs over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities."[14] The proposed time horizon requirements would benefit from additional clarifications, since the proposed requirements apply to two distinct time periods. The first is the "planning horizon" over which transmission needs are determined. This timeframe differs from the time horizon over which the economic benefits (cost savings) of transmission projects are evaluated and compared to project costs. It would be useful to clarify further that the proposed *minimum* 20-year requirement applies to both the "*planning horizon*" (over which needs are determined) and the "*benefit-cost analysis horizon*" (over which benefits are compared to costs), but that these two timeframes do not have to be identical.

25. I believe setting a 20 year *minimum* for both types of time horizons is reasonable. However, it would be better to align these two time periods with (1) the time horizon over which public policy requirements are specified; and (2) the expected useful life of the transmission project evaluated.

26. There is almost universal agreement that the time horizon over which transmission *needs* have to be assessed should be at least as long as the planning and development timeframes of

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[12] Order on Local Transmission and Distribution Planning Process Pursuant to the Accelerated Renewable Energy Growth and Cmty. Benefit Act, NY Pub. Svc. Comm'n. (Sept. 9, 2021) *at* https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6A0FAE50-5710-42DD-969A-5116171E2457}, implementing recommendations made in the *Initial Report of the New York Power Grid Study*, Jan. 19, 2021, Ch. 3, *available at*: https://www.nyserda.ny.gov/About/Publications/Research-and-Development-Technical-Reports/Electric-Power-Transmission-and-Distribution-Reports/Electric-Power-Transmission-and-Distribution-Reports---Archive/New-York-Power-Grid-Study.

[13] NOPR at P 78.

[14] *Id.* at P 56.

major transmission projects, which often is a decade (if not more). However, while this approach would allow for the approval of projects that could realistically be completed before a specified need for the project first arises, such a "first-needs-based" approach is entirely incapable of identifying the most cost-effective solutions to address the multiple needs that a transmission project can address (and the benefits it provides) over the course of its useful life. For example, while a limited upgrade to a 230 kV transmission facility may address a specific reliability or generation-interconnection need within the next 10 years, a larger-scale 345 kV transmission investment may be more cost effective because it can address multiple needs that would likely arise in the decade after the initial reliability need has to be addressed. For example, in addition to addressing the most pressing reliability need, the 345 kV upgrade may offer a lower-cost solution for longer-term generation interconnection needs, additionally reducing congestion and renewable curtailments, and addressing multiple subsequent reliability needs that arise over the subsequent decade.

27. In other words, to capture these opportunities rightsizing transmission projects that can address multiple long-term transmission needs at lower cost, the *planning horizon for identifying transmission needs* should cover at least the time horizon for which public policies are specified (*e.g.*, the next 20 years for 2040 clean energy mandates or the next 30 years for 2050 goals). This alignment is important, for example, because the optimal portfolio of transmission investments made between 2030 and 2040 will in part be a function of how the already-specified public policy needs continue to change over the following decade.

28. With respect to the *time horizon applied to benefit-cost analyses*, it would be more reasonable to require that the identified transmission investments' costs and benefits be compared over the 40–50 year cost-recovery lifespan of the transmission assets. This approach is currently used by number of RTOs, even though economic planning scenarios may extend only 20 years into the future. Where the cost-recovery life of transmission projects extends beyond the horizon of the projected scenarios, estimates of benefits beyond the scenario horizon (*e.g.*, beyond year 20) can be derived through extrapolation (*e.g.*, by indexing with inflation the estimated benefits for year 20). This approach yields a stream of benefits for the remaining cost-recovery lifespan of the transmission assets.[15] Without doing so, the benefit-cost ratio

[15] Such extrapolation approaches are routinely used by MISO, SPP, California Independent System Operator ("CAISO"), and NYISO for estimating the 40–50 year present value of transmission benefits.

of the investments will typically be understated because benefits tend to grow over time (*e.g.*, with fuel costs, load growth, and more stringent clean-energy and emissions standards), while project costs (*i.e.*, transmission revenue requirements) will tend to decline over time as the asset is depreciated. A benefit-cost analysis that compares only the first 20 years of (typically increasing) benefits with the first 20 years of (declining) transmission revenue requirements will understate the overall cost effectiveness of the investment.

29. I thus recommend that the Commission clarify and address this point in the final rulemaking to require that: (1) the long-term planning horizon used to determine transmission needs be at least 20 years, but ideally cover the entire period over which public policy needs are specified; and (2) the time horizon over which economic benefits are compared to project costs should be at least 40 years to cover the cost-recovery period of the projects evaluated—though recognizing that this will generally require extrapolations of benefits beyond the horizon (*e.g.*, 20 years) over which market conditions are simulated.

6. Long-Term Transmission Planning Should be Focused on Portfolios of Transmission Projects that Cost-Effectively Address the Broad Range of Future Needs

30. The Transmission Planning NOPR would give transmission planners the flexibility to use a portfolio approach in the evaluation of benefits of regional transmission facilities as part of their long-term regional transmission planning process. I concur with the NOPR's rationale that doing so will provide administrative efficiencies, will tend to result in benefits that are more evenly distributed and stable over time, and will thereby facilitate regional cost allocation.[16] In addition, a portfolio-based planning process will be necessary to address the broad range of long-term regional transmission needs in a cost-effective fashion. This is because long-term transmission needs are not a collection of separable needs that apply to individual locations on the grid so that they could be addressed cost-effectively through an individual transmission project. Rather the "needs" are defined by reliability, market-efficiency, and public policy requirements that occur simultaneously and tend to cover large geographic areas—such as entire sub-regional, regional, or multi-regional footprints. To

[16] Note that, in addition to MISO utilizing a portfolio-based approach for its multi-value planning process, SPP has long utilized a portfolio-based approach in its Regional Cost Allocation Review process to ensure that its highway-byway cost allocation approach results in benefits that are commensurate with the costs allocated.

identify transmission solutions that can cost-effectively address the multiple needs in a geographically-expansive footprint will necessarily require a portfolio of transmission projects that can work in unison to cost-effectively support the full set of needs of the long-term time horizon. To achieve the benefits (cost savings) offered by simultaneously addressing the full range of long-term needs will require the design of a portfolio of individual transmission projects that, as a group, offers significant synergies and cost savings. Quantifying the overall benefits offered by such a solution will similarly require quantifying the total benefits offered by the entire portfolio, because an individual project may not be able to yield the full benefit without the synergies provided through its interaction with other projects in the portfolio. Of course, a number of different portfolios and portfolio-configurations will need to be evaluated in order to design a portfolio of transmission projects that performs best across the range of uncertain long-term futures analyzed through the scenario planning effort.

7. Proactive, Scenario-Based, Multi-Value Planning Needs to Be Used to Mitigate Risk and Create Insurance Value to Avoid High-Cost Outcomes

31. The Transmission Planning NOPR recognizes that:

> transmission infrastructure can also serve as a form of insurance for the uncertainties of the future, because a more robust, integrated transmission system has the potential to afford consumers the benefits of competition and enhanced reliability even if supply and demand fundamentals change over time.[17]

32. The NOPR further recognizes that transmission can provide such value through the "mitigation of extreme events and system contingencies," which can be estimated "as the probability-weighted savings from reducing production and power purchase costs during a number of simulated extreme events."[18] The NOPR then proposes to require that transmission planners develop transparent project selection criteria that "seek to maximize benefits to consumers over time without over-building transmission facilities.[19]

33. In the context of evaluating multiple long-term scenarios and factors such as transmission value during extreme weather and other challenging market conditions, the specification of

[17] NOPR at P 29.

[18] *Id.* at PP 206–207.

[19] *Id.* at P 245.

project selection criteria becomes an objective that needs to consider both the expected costs and risks associated with transmission solutions. From a customer-cost perspective, criteria based on the average or "expected" (*i.e.*, probability-weighted average) total costs borne by electricity customers across scenarios and market conditions evaluated with and without the contemplated transmission investments will be appropriate. As discussed above, transmission investments that yield the highest expected "net benefit" will maximize benefits to customers—because, as discussed above, if the benefits (*i.e.*, reduction in other costs) associated with the transmission solution exceed the costs of the transmission solution, total customer costs are reduced even if transmission costs increase.

34. However, selection criteria focused on average or expected values across scenarios will not address the extent to which transmission investments can reduce the considerable risks that the industry and its customers face in both the short- and long-term. These risks include both the near-term risk of challenging market conditions (such as extreme weather events that are associated with high costs and possible service outages) as well as the long-term risk associated with uncertainties over the next decades, such as uncertainties about public policy requirements, technology costs and adaptation, fuel costs, and load growth (including advanced transmission and storage technologies, electric vehicle adaption, and economy-wide electrification). These long-term uncertainties need to be reflected in the scenarios selected to describe the range of plausible futures that are analyzed in the transmission planning effort.

35. Selection criteria based solely on the average or (where available) the probability-weighted average across simulated short-term and long-term market conditions would assume that policymakers, regulators, and electricity consumers are "risk neutral"—which they are not. Customers are often willing to pay a "premium" to reduce risks that can be insured. It is therefore important that selection criteria consider the extent to which short- and long-term uncertainties impose (cost and reliability) risks on electricity customers and the extent to which transmission investments would reduce or mitigate these risks. For example, if two transmission solutions offer the same expected value of customer benefits across the scenarios and market conditions analyzed but one of them is associated with lower risks, that risk mitigation value should be reflected in the project selection criteria. If the transmission solution that offers risk mitigation is somewhat more expensive (*e.g.*, because it requires the

selection of transmission facilities, such as single circuit lines on double circuit towers, that can be expanded more easily under certain future market conditions), transmission planners, stakeholders, and policymakers will have to be able to consider the tradeoff between higher cost solutions and the risk mitigation they offer. If one transmission solution avoids certain high cost outcomes (or extremely-high cost but low probability reliability events) planners, stakeholders, and policymakers may all agree that the "insurance value" of this transmission solution exceeds the added cost, if any, that may be associated with that solution. For example, when the Texas commission approved the transmission design associated with its Competitive Renewable Energy Zone (CREZ) effort, it approved utilizing double circuit transmission towers for the construction of single circuit lines, which created the option to expand the capability of the lines quickly and at low costs in the future—a valuable option that has since been exercised.[20]

36. Project selection criteria that consider risk mitigation include "least regrets" selection criteria and "maximum regrets" metrics. Least regrets selection criteria try to find solutions that minimize the likelihood of regrettable (high cost or low reliability) outcomes. For example, least regrets planning may try to select solutions that minimize the extent to which total customer costs (including reliability costs) associated with the selected solution deviate from alternative solutions that would be least-cost for only a specific scenario or market outcome, when compared across all scenarios and market conditions evaluated. In other words, least-regrets planning attempts to find solutions that, given short- and long-term uncertainties, perform well across all scenarios and market conditions analyzed, while not necessarily representing the least-cost (or highest benefit) solution for any one of the possible future scenarios and market conditions. Such least-regrets solutions reduce the probability of customers being exposed to very high-cost outcomes ("maximum regrets") that could be associated with a transmission infrastructure that either is overbuilt (*i.e.*, avoid the regret that, with the benefit of hindsight, too much was spent on transmission) or one that is insufficiently

[20] As ERCOT system planners explained in 2014, this initial design made it possible that "[s]everal transmission improvements can be implemented at a relatively low cost and in a relatively short time frame to increase the Panhandle export capability. These include installing shunt reactors, synchronous condensers, and *adding the second circuit on the existing towers that were constructed to be double-circuit capable with originally just one circuit in place*." ERCOT, Panhandle Renewable Energy Zone (PREZ) Study Report, April 2014, p. iii (emphasis added), *at*: https://www.ercot.com/files/docs/2014/04/21/panhandle_renewable_energy_zone_study_report.pdf

robust (*i.e.*, avoid the regret that the lack of transmission capability leads to high customer costs and low reliability).

37. I recommend that the Commission require transmission planners to develop project selection criteria, such as those discussed above, that consider the extent to which transmission investments can reduce risks, even if the risk mitigation is associated with added costs. Documenting the risk and risk mitigation opportunities in a transparent fashion will allow planners, stakeholders, and policymakers to consider the tradeoffs in selecting from the available transmission solutions.

38. I also recommend that planners steer away from "no regrets" selection criteria that require transmission investments to offer net benefits in *every one* of the scenarios analyzed. While such no-regrets criteria would minimize the likelihood of encountering a future with an overbuilt transmission infrastructure (*i.e.*, and the "regret" of having incurred transmission costs that have not produced benefits in excess of costs), such no-regrets criteria entirely overlook the risk of regrettable future outcomes under which customers are exposed to very high costs and poor reliability in other futures because the contemplated transmission investments were not made.

39. For example, in its Planning Analysis of the Paddock-Rockdale Project, American Transmission Company evaluated the benefit that the project would provide under seven plausible future scenarios.[21] The benefit-cost analysis, which quantified a wide range of transmission-related benefits, found that the 40-year present value of the project's customer benefits fell $56 million short of the project's $136 million 40-year present value of revenue requirement in the "Slow Growth" future.[22] Thus, the project would not have satisfied a "no regrets" selection requirement. However, the scenario analyses also showed the present value of the project's quantified benefits exceeded the project's costs (thus producing net benefits that reduced total customer costs) in the six other scenarios analyzed. In three of the seven scenarios, quantified customer benefits exceeded project costs by $350–410 million, while in two scenarios (the "Fuel Supply Disruption" and "High Plant Retirements" futures),

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[21] American Transmission Company, *Planning Analysis of the Paddock-Rockdale Project*, Apr. 5, 2007, *available at:* http://www.atcllc.com/oasis/Customer_Notices/Filed_CPCN_Economic_Analysis_PR_051607.pdf.

[22] *Id*. at 5, Table 1.

customers would have been $710 million worse off without the project.[23] Thus, while not offering a "no regrets" solution given the range of future uncertainties, the project offered an attractive "least-regrets" solution: with estimated customer benefits falling short of transmission project costs in only one of the seven futures analyzed, but benefits significantly exceeding costs in six of the seven future scenarios. In addition, while the projected "maximum regret" of *building* the project was $56 million of higher customer costs (negative net benefits) in the Slow Growth future, the "maximum regret" of *not building* the project was $710 million of higher customer cost (positive net benefits) in the Fuel Supply Disruption and High Plant Retirements futures.[24]

8. Additional Coordination between Long-Term Transmission Planning and Generation Interconnection is Necessary

40. The Transmission Planning NOPR recommends that long-term transmission planning should consider regional transmission facilities that the "utility 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)."[25] I concur with this recommendation. To achieve cost-effective transmission solutions, it is critical that generation interconnection processes be coordinated and integrated with long-term transmission planning, which should also assess generation interconnection needs related to achieving public policy goals. I am concerned, however, that the proposed mechanism will be ineffective and insufficient to yield cost-effective outcomes. Solely relying on transmission needs identified in past interconnection studies is not sufficiently forward looking because the interconnection request received to date will generally have been submitted in response to near- and intermediate-term resource needs, and will not address long-term needs.

41. To address this gap, I recommend that the Commission additionally require that the scenario-based long-term transmission planning effort identify multi-value transmission solutions that can most cost-effectively create the "headroom" necessary to interconnect the generating resources necessary to meet the region's and its individual states' public policy

[23] *Id.*

[24] *Id.*

[25] NOPR at P 166

requirements.[26] Doing so would not preclude cost allocations under which interconnecting generators contribute to a portion of the associated transmission costs. As MISO's recent long-term planning process and proposed multi-value transmission portfolio have shown, doing so leads to the proactive development of grid upgrades that provide substantial economic benefits and facilitate the more cost-effective interconnection of the generating resources necessary to meet long-term state public policy goals in addition to reliability and economic needs.[27]

9. To Be Effective, New Long-Term Transmission Planning Processes Need to be Integrated with Existing (Nearer-Term) Transmission Planning Processes

42. Most regional planning processes have separate processes to address local needs, regional reliability needs, economic or market efficiency needs, public policy needs, and interregional needs. A notable exception is SPP, which uses its Integrated Transmission Planning (ITP) process to simultaneously address reliability, economic, and public policy needs.[28] The Transmission Planning NOPR does not propose to fundamentally modify these existing planning processes. In fact, the Commission specifically notes that "…we do not propose to require that public utility transmission providers modify their existing regional transmission planning processes that plan for reliability and economic transmission needs to incorporate Long-Term Scenarios."[29] However, the NOPR also asks "whether public utility transmission providers should be required to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes to identify more efficient or cost-effective transmission facilities than are identified through those processes today."[30]

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[26] For a more detailed discussion of coordinating generation interconnection processes with transmission planning processes, see Johannes Pfeifenberger, *Generation Interconnection and Transmission Planning*, ESIG Joint Generator Interconnection Workshop (Aug. 9, 2022), *at*: https://www.brattle.com/insights-events/publications/generation-interconnection-and-transmission-planning/

[27] See ACORE, *Enabling Low-Cost Clean-Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long-term Transmission Planning*, (Aug. 9, 2022),*at:* https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf ("ACORE 2022")

[28] SPP, *Integrated Transmission Planning Manual* 1-2 (Feb. 15, 2022), *at* https://www.spp.org/Documents/60911/ITP%20Manual%20Version%202.10.pdf

[29] NOPR at P 89.

[30] *Id.* at P 90.

43. I offer two recommendations. First, it is important that the creation of a new long-term planning process does not disrupt the existing planning processes that address local reliability, regional reliability, generation interconnection, transmission service requests, regional economic and public policy needs, or interregional needs. Disrupting the existing processes could delay transmission upgrades necessary to address more urgent and near-term transmission needs. Second, coordination between new long-term planning processes and the existing (more near-term) processes will be necessary to implement more cost-effective, multi-value transmission solutions in the long term while continuing to be able to react to short- and near-term needs that may change (often quickly) between two long-term planning cycles.

44. If multi-value regional (and interregional) transmission needs and solutions are identified through the long-term planning process that can cost-effectively address a wide range of different long-term needs, it is important that coordination between the new long-term and existing targeted planning processes ensures that these long-term needs and solutions are fully considered in the more targeted near-term planning processes. Achieving such an outcome requires two levels of coordination. First, it is critical that long-term planning processes can result in the recommended development of multi-value transmission solutions to address the identified needs. The approval of such multi-value projects would then have to be reflected in the more targeted and more near-term transmission planning and generation interconnection processes. In this case, the targeted near-term planning processes would only be used to "fill in" the more urgent and missing pieces—such as local and lower-voltage transmission needs or unexpected new needs that may not have been addressed through the approved multi-value transmission projects. An example of this approach is MISO's long-term planning process that resulted in the recent approval of a portfolio of multi-value transmission projects that will address a range of future reliability needs, market efficiency needs, and—by facilitating the interconnection of over 50 GW of new generating resources—help cost-effectively meet the region's public policy needs.[31] As MISO continues to utilize its more targeted reliability, generation interconnection, and market-efficiency planning processes, these existing processes will be able to take advantage of the capabilities

[31] ACORE 2022 at 1–2

associated with the new MVP transmission facilities and address only changing and incremental needs.

45. The second element to achieving effective coordination between new long-term, multi-value planning processes and the more targeted existing transmission planning processes is a requirement that future transmission needs identified through the long-term planning process (but not yet addressed through the approval of transmission solutions) be used to inform existing planning processes as they address more targeted (and often more near-term) needs. Consideration of the identified (but not yet addressed) long-term needs in targeted planning processes is critical to avoid outcomes under which the targeted existing processes implement transmission upgrades narrowly focused on the near-term need when a different multi-value transmission project could more cost-effectively address both targeted near-term needs as well as the already-identified longer-term needs, as is frequently occurring today.

46. In other words, even beyond considering any transmission projects approved through long-term planning processes, it is necessary to modify the existing planning processes such that long-term study information about not-yet-addressed future transmission needs can be used to modify the transmission solutions that otherwise would be selected through the targeted existing planning process. For example, assume addressing a near-term reliability need would require the rebuilding of an aging existing single-circuit 115 kV line with larger conductors and stronger new towers to increase the line's transfer capability. If the long-term transmission planning analysis has identified the need for substantially more transfer capability in the future (*e.g.,* to meet additional future public policy needs), it may be reasonable to rebuild the line as a single-circuit 345 kV line on double circuit towers but operate it at 115 kV initially. If and when the additional transfer capability is then needed in the future, the added transfer capability could be achieved cost-effectively by either increasing the voltage level of the line, adding the second circuit, or both. While the initial cost of rebuilding the existing line for 345 kV would be more expensive, the "upsizing" of the initial investment to address the near-term reliability need would create the option to cost-effectively add significant transfer capability in the future. The long-term study results would provide the information necessary to decide if the additional cost of creating this option is a "least-regrets" investment. In short, even if the needs identified in the targeted planning processes are urgent, incorporating the results from the prior long-term planning process may

suggest modifications to the solution (*e.g.* a scaled-up project) that can address the urgent need while simultaneously and more cost-effectively addressing identified longer-term needs.

47. In combination, these two elements of coordinating new long-term, multi-value transmission planning processes with the existing (generally more targeted) planning processes would ensure that more cost-effective, least-regrets solutions are identified and realized to address the wide range of near-term and long-term transmission needs. Because near-term forecasts of transmission needs are more certain than long-term outlooks of transmission needs, I agree with the Commission's proposal to not require that scenario-based planning be added to the existing processes as doing so is not necessary for near-term planning. However, the existing planning processes often are inefficient in that they are overly targeted to address specific needs, such as reliability needs, without considering other near-term transmission needs, such as near-term market efficiency and public policy needs. It will not be possible to select the most cost effective solutions to near-term transmission needs unless these near-term planning processes also consider the multiple transmission needs that may exist. To remedy this shortcoming of targeted existing planning processes, I recommend that the Commission require that the scope of existing planning processes be widened to apply a multi-value planning perspective. As discussed above, the near-term planning decisions need to be informed by the results of the new long-term planning efforts.

48. This concludes my affidavit.

<u>CERTIFICATION</u>

I hereby certify that I have read the affidavit signed and know its contents are true as stated to the best of my knowledge and belief. I possess full power and authority to sign this filing.

Respectfully Submitted,

Johannes Pfeifenberger

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August 16, 2022

ATTACHMENT A

TO

AFFIDAVIT OF JOHANNES P. PFEIFENBERGER ON BEHALF OF NATURAL RESOURCES DEFENSE COUNCIL

ATTACHMENT JPP-1: QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

Johannes Pfeifenberger is a Principal of The Brattle Group where he is a member of the firm's Utility Regulation and Electric Power practices. He received a M.A. in Economics and Finance from Brandeis University and holds a B.S. and M.S. ("Diplom Ingenieur") in Electrical Engineering, with a specialization in Power Engineering and Energy Economics, from the University of Technology in Vienna, Austria.

Mr. Pfeifenberger is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), and an IEEE Senior Member. He frequently serves as an advisor to research initiatives by the Energy Systems Integration Group (ESIG) and the US Department of Energy's National Labs. Before joining Brattle, he was a Consultant for Cambridge Energy Research Associates and a Research Analyst at the Institute of Energy Economics of the University of Technology in Vienna, Austria.

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Mr. Pfeifenberger has also presented research findings related to mergers and network access matters to government and antitrust enforcement agencies, including the U.S. Department of Justice, the Merger Task Force of the European Community, the German Cartel Office, the German Ministry of Economics, and the White House National Economic Council.

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