DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM21–17–000; Order No. 1920]

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Final order.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises the *pro forma* Open Access Transmission Tariff (OATT) to remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements. In this final order, the Commission requires transmission providers to conduct Long-Term Regional Transmission Planning that will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs. The Commission also directs other reforms to improve coordination of regional transmission planning and generator interconnection processes, require consideration of certain alternative transmission technologies in regional transmission planning processes, and improve transparency of local transmission planning processes and coordination between regional and local transmission planning processes. These reforms are intended to ensure that existing regional and local transmission planning and cost allocation requirements are just, reasonable, and not unduly discriminatory or preferential.

DATES: This final order is effective August 12, 2024.

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SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction and Background

1. In this final order, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements.[1] The reforms herein will remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements to ensure that the rates, terms, and conditions for transmission service provided by public utility transmission providers (transmission providers) [2] remain just and reasonable and not unduly discriminatory or preferential. This final order builds upon Order No. 888, Order No. 890,[3] and Order No. 1000,[4] in which the Commission incrementally developed the requirements that govern regional transmission planning and cost allocation processes to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. Specifically, in this final order, we find that there is substantial evidence to support the conclusion that the existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; [5] (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. Accordingly, we believe that it is necessary to revisit existing transmission planning and cost allocation requirements. We conclude that adopting the reforms of this final order, as previously contemplated in the notice of proposed rulemaking (NOPR),[6] will remedy the identified deficiencies in existing regional and local transmission planning and cost allocation requirements, as discussed below, and will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

2. Specifically, the reforms adopted in this final order require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[7] This final order adopts specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning, including, among other things, the use of scenarios to identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs.

3. This final order also requires transmission providers to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning. In addition, this final order requires transmission providers to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities and requires that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[8]

4. This final order requires transmission providers to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.

5. Further, this final order requires transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected. This final order further permits, but does not require,

[1] 16 U.S.C. 824e.

[2] Section 201(e) of the FPA, 16 U.S.C. 824(e), defines ''public utility'' to mean ''any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter.'' As stated in the Order No. 888 *pro forma* Open Access Transmission Tariff (OATT), ''transmission provider'' is a ''public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.'' *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp.* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y.* v. *FERC,* 535 U.S. 1 (2002); *Pro forma* OATT section I.1 (Definitions). The term ''transmission provider'' includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO).

[3] *Preventing Undue Discrimination & Preference in Transmission Serv.,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, 118 FERC ¶ 61,119 (2007), *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification,* Order No. 890–B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[4] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.,* Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000–A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[5] All capitalized terms are defined below. *Infra* Use of Terms section.

[6] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028 (2022) (NOPR); *see also Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* 86 FR 40266 (July 27, 2021), 176 FERC ¶ 61,024 (2021) (advanced notice of proposed rulemaking (ANOPR)).

[7] For purposes of this final order, and consistent with Order No. 1000, a transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 160.

[8] We recognize that some transmission planning regions may include Long-Term Regional Transmission Facilities, or a portfolio of such Facilities, in a regional transmission plan, but may not necessarily include these Facilities for purposes of cost allocation. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 63. For purposes of this final order, unless otherwise noted, when referencing Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected, we intend ''selected'' to mean that those Facilities are selected in the regional transmission plan for purposes of cost allocation.

transmission providers to adopt a State Agreement Process, wherein Relevant State Entities agree to such a State Agreement Process that would provide up to six months after selection for its participants to determine, and transmission providers to file, a cost allocation method for specific Long-Term Regional Transmission Facilities. This final order establishes a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities.

6. This final order also requires transmission providers to include in their OATTs a process to provide Relevant State Entities and interconnection customers the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria. This final order requires transmission providers to include in their OATTs provisions that require transmission providers—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected.

7. In addition, this final order requires that transmission providers evaluate for potential selection in their existing Order No. 1000 regional transmission planning processes regional transmission facilities that will address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades [9] originally identified through the generator interconnection process.

8. This final order requires transmission providers in each transmission planning region to consider more fully the alternative transmission technologies of dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning and cost allocation processes.

9. This final order does not finalize the NOPR proposal to not permit transmission providers to take advantage of the recovery of 100% of construction work in progress for Long-Term Regional Transmission Facilities, and the Commission will instead continue to consider transmission incentives issues in other proceedings. This final order similarly does not finalize the NOPR proposal with respect to permitting the exercise of Federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal establishing joint ownership of the transmission facilities, and the Commission will instead continue considering the NOPR proposal and potential Federal right of first refusal issues in other proceedings.

10. This final order adopts the NOPR proposal to require transmission providers to adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to ''right-size'' replacement transmission facilities.

11. This final order requires transmission providers to revise their interregional transmission coordination processes to reflect the Long-Term Regional Transmission Planning reforms adopted in this final order. This final order also requires that transmission providers meet additional information sharing and transparency requirements with respect to their interregional transmission coordination processes.

12. This final order requires that each transmission provider submit a compliance filing within ten months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction to demonstrate that it meets the requirements of this final order, with the exception of those requirements adopted in the Interregional Transmission Coordination section in this final order. This final order requires that each transmission provider submit a compliance filing within 12 months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final order.

13. We recognize that transmission providers have ongoing efforts to address transmission planning and cost allocation. This final order is not intended to interfere with the potential progress represented by those efforts, and we encourage transmission providers to continue to innovate to improve their transmission planning and cost allocation processes.

A. Historical Framework: Order Nos. 888, 890, and 1000

14. Over the last several decades, the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000. In 1996, the Commission issued Order No. 888, which implemented open access to transmission facilities owned, operated, or controlled by a public utility and included certain minimum requirements for transmission planning. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT after more than 10 years of experience since Order No. 888. Among other OATT reforms, the Commission required all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[10]

15. In 2011, the Commission recognized the need for further transmission planning reforms with its issuance of Order No. 1000. The Commission based the reforms it adopted in Order No. 1000 on changes in the energy industry, its experience implementing Order No. 890, and a robust record developed through technical conferences and comments

[9] The Commission's *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) provide that, ''Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.'' *See Improvements to Generator Interconnection Procedures & Agreements,* Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at P 13 n.23, *order on reh'g,* 185 FERC ¶ 61,063 (2023), *order on reh'g,* Order No. 2023–A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199 (2024). In this final order, we refer to network upgrades developed through the generator interconnection process as interconnection-related network upgrades.

[10] Order No. 890, 118 FERC ¶ 61,119 at PP 418–601.

from a diverse range of stakeholders.[11] The Commission stated in Order No. 1000 that ''the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost.'' [12] In establishing the requirements of Order No. 1000, the Commission found that the existing requirements of Order No. 890 were not adequate, noting that Order No. 1000 ''expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters.'' [13] The Commission then enumerated multiple concerns that it had regarding existing transmission planning practices, including concerns about: (1) the lack of an affirmative obligation to develop a transmission plan evaluating if a regional transmission facility ''may be more efficient or cost-effective than solutions identified in local transmission planning processes''; (2) the lack of a requirement to address Public Policy Requirements; [14] (3) the Federal right of first refusal for incumbent transmission developers to build upgrades to their existing transmission facilities; (4) the lack of procedures to identify and evaluate the benefits of interregional transmission facilities; and (5) cost allocation for regional and interregional transmission facilities.[15]

16. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the *pro forma* OATT could support the development of more efficient or cost-effective transmission facilities.[16] The reforms in Order No. 1000 included: (1) regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost allocation, including a set of principles for each category of cost allocation; and (5) interregional transmission coordination. The reforms focused on the process by which transmission providers engage in regional transmission planning and the associated cost allocation rather than on the outcomes of the process.[17]

17. Among other regional transmission planning reforms in Order No. 1000, the Commission required that the following Order No. 890 transmission planning principles apply to regional transmission planning processes: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.[18]

18. In addition, with respect to the Order No. 1000 reforms, the Commission made a distinction between a transmission facility ''included'' in a regional transmission plan and a transmission facility ''selected.'' A transmission facility selected in a regional transmission plan for purposes of cost allocation is a transmission facility that has been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective transmission facility needed to meet regional transmission needs. Both regional transmission facilities and interregional transmission facilities are eligible for potential ''selection'' in a regional transmission plan for purposes of cost allocation.[19]

19. Selected transmission facilities often will not comprise all of the transmission facilities that are included in a regional transmission plan.[20] Some transmission facilities are merely ''rolled up'' and listed in a regional transmission plan without going through an analysis at the regional level, and/or are merely considered for reliability implications upon a transmission system, and therefore, are not eligible for selection and regional cost allocation.[21] For example, a local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected.[22] Thus, a local transmission facility may be rolled up and ''included'' in a regional transmission plan for informational purposes, but it is not ''selected.''

B. ANOPR and Technical Conference

20. In July 2021, the Commission issued the ANOPR [23] presenting potential reforms to improve the regional transmission planning and cost allocation and generator interconnection processes. In issuing the ANOPR, the Commission noted that, in part because more than a decade had passed since Order No. 1000, it was now an appropriate time to review its regulations governing regional transmission planning and cost allocation to determine whether reforms are needed to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.[24] The Commission noted that the electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources that may often be located far from load centers. The Commission also highlighted the growth of new resources seeking to interconnect to the transmission system and that the differing characteristics of those resources are creating new demands on the transmission system. The Commission explained that ensuring just and reasonable Commission-jurisdictional rates during these changes, while maintaining grid reliability, remains the Commission's priority in adopting requirements for the regional transmission planning and cost allocation and generator interconnection processes. As a result, the Commission issued the ANOPR to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly

[11] For purposes of this final order, and consistent with Order No. 1000, a stakeholder includes any party interested in the transmission planning processes. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 151 n.143.

[12] *Id.* P 2.

[13] *Id.* P 21.

[14] Public Policy Requirements are requirements established by local, state, or Federal laws or regulations (*i.e.,* enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether within a state or at the Federal level). *Id.* P 2. Order No. 1000–A clarified that Public Policy Requirements include local laws or regulations passed by a local governmental entity, such as a municipal or county government. Order No. 1000–A, 139 FERC ¶ 61,132 at P 319.

[15] Order No. 1000, 136 FERC ¶ 61,051 at P 3.

[16] *Id.* PP 11–12, 42–44; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 3, 4–6.

[17] Order No. 1000, 136 FERC ¶ 61,051 at P 12.

[18] The Commission did not include the regional participation or cost allocation transmission planning principles with respect to regional transmission planning processes because those issues were addressed by other reforms in Order No. 1000. *Id.* P 151.

[19] *Id.* P 63. A regional transmission facility and an interregional transmission facility are defined below. *Infra* Use of Terms section.

[20] Order No. 1000, 136 FERC ¶ 61,051 at P 63.

[21] *Id.* PP 7, 226, 318.

[22] *Id.* P 63. The Commission clarified in Order No. 1000–A that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider's retail distribution service territory, if it has one; otherwise, the area is defined by the public utility transmission provider's footprint. In the case of an RTO/ISO whose footprint covers the entire region, a local transmission facility is defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members. Order No. 1000–A, 139 FERC ¶ 61,132 at P 429.

[23] ANOPR, 176 FERC ¶ 61,024.

[24] *Id.* P 3.

discriminatory or preferential and that reliability is maintained.

21. On November 15, 2021, the Commission convened a staff-led technical conference (November 2021 Technical Conference or Technical Conference) to examine in detail issues and potential reforms related to regional transmission planning as described in the ANOPR. Specifically, the Technical Conference included three panels covering issues to consider in long-term scenarios, consideration of long-term scenarios in regional transmission planning processes, and identifying geographic zones with high renewable resource potential for use in regional transmission planning processes.[25] Following the Technical Conference, the Commission invited all interested persons to file comments to address issues raised during the Technical Conference.

C. Joint Federal-State Task Force on Electric Transmission

22. On June 17, 2021, the Commission established a Joint Federal-State Task Force on Electric Transmission (Task Force) to formally explore broad categories of transmission-related topics.[26] The Commission explained that the development of new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Given that Federal and state regulators each have authority over transmission-related issues and given the impact of transmission infrastructure development on numerous different priorities of Federal and state regulators, the Commission determined that the topic was ripe for greater Federal-state coordination and cooperation.[27] The Task Force was composed of all sitting FERC Commissioners as well as representatives from 10 state commissions nominated by the National Association of Regulatory Utility Commissioners (NARUC), with two originating from each NARUC region.[28]

23. The Task Force has convened multiple formal meetings with eight meetings held thus far to discuss regional transmission planning and cost allocation issues, convening on November 10, 2021, February 16, 2022, May 6, 2022, July 20, 2022, November 15, 2022, February 15, 2023, July 16, 2023, and February 28, 2024.

24. The discussion at the November 2021 meeting was focused on incorporating state perspectives into regional transmission planning.[29] The February 2022 meeting included discussion of specific categories and types of transmission benefits that transmission providers should consider for the purposes of transmission planning and cost allocation.[30] The May 2022 meeting focused on barriers to the efficient, expeditious, and reliable interconnection of new resources.[31] The July 2022 meeting focused on interregional transmission planning and transmission project development and the NOPR.[32] The November 2022 meeting focused on regulatory gaps and challenges in oversight of transmission development.[33] The February 2023 meeting focused on the physical security of the Nation's transmission system, and featured guest speakers from the North American Electric Reliability Corporation and US DOE.[34] The July 2023 meeting focused on grid enhancing technologies, featuring a guest speaker from the Electric Power Research Institute.[35] The February 2024 meeting focused on transmission siting, featuring guest speakers from US DOE.[36]

25. In light of the Task Force expiring three years from its first public meeting, *i.e.,* on November 10, 2024,[37] on March 21, 2024, the Commission established the Federal and State Current Issues Collaborative (Collaborative).[38] The Collaborative will be comprised of all Commissioners, as well as representative from 10 state commissions. The Collaborative will provide a venue for Federal and state regulators to share perspectives, increase understanding, and where appropriate, identify potential solutions regarding challenges and coordination on matters that impact specific state and Federal regulatory jurisdiction.[39]

D. Notice of Proposed Rulemaking

26. On April 21, 2022, the Commission issued the NOPR, proposing reforms focused on long-term regional transmission planning and cost allocation processes. In particular, the Commission proposed in the NOPR that transmission providers in each transmission planning region participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[40] The Commission also proposed to require that transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[41]

27. The Commission proposed that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the relevant interconnection request(s).[42]

28. The Commission proposed 12 benefits that transmission providers may consider in Long-Term Regional Transmission Planning and cost allocation processes.[43] The Commission stated that the list of potential benefits was neither mandatory nor exhaustive, and that pursuant to the proposal, transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.[44]

29. The Commission proposed, with regard to the selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation, to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs: (1) transparent and not unduly

[25] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Further Supplemental Notice of Technical Conference, Docket No. RM21–17–000 (issued Nov. 12, 2021) (attaching agenda).

[26] *Joint Fed.-State Task Force on Elec. Transmission,* 175 FERC ¶ 61,224, at PP 1, 6 (2021).

[27] *Id.* P 2.

[28] An up-to-date list of Task Force members, as well as additional information on the Task Force, is available on the Commission's website at: *https://www.ferc.gov/TFSOET.* Public materials related to the Task Force, including transcripts from public meetings, are available in the Commission's eLibrary in Docket No. AD21–15–000.

[29] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Oct. 27, 2021) (attaching agenda).

[30] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Feb. 2, 2022) (attaching agenda).

[31] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Apr. 22, 2022) (attaching agenda).

[32] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued June 30, 2022) (attaching agenda).

[33] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Nov. 1, 2022) (attaching agenda).

[34] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Feb. 1, 2023) (attaching agenda).

[35] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued June 30, 2023) (attaching agenda).

[36] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Feb. 13, 2024) (attaching agenda).

[37] *Joint Fed.-State Task Force on Elec. Transmission,* 175 FERC ¶ 61,224 at P 4.

[38] *Joint Fed.-State Task Force on Elec. Transmission,* 186 FERC ¶ 61,189 (2024).

[39] *Id.* PP 5–6.

[40] NOPR, 179 FERC ¶ 61,028 at PP 64, 68.

[41] *Id.* P 84.

[42] *Id.* P 166.

[43] *Id.* P 185.

[44] *Id.* P 184.

discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection that address transmission needs driven by changes in the resource mix and demand; and (2) a process to coordinate with the Relevant State Entities in developing such criteria.[45]

30. The Commission proposed to require transmission providers to more fully consider the incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices in regional transmission planning and cost allocation processes.[46]

31. The Commission proposed to require, with regard to allocating the costs of Long-Term Regional Transmission Facilities, transmission providers to revise their OATTs to include: (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.[47] The Commission proposed to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[48] The Commission proposed to require transmission providers to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.[49]

32. The Commission further proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of construction work in progress costs in rate base in certain circumstances for Long-Term Regional Transmission Facilities.[50]

33. Finally, the Commission proposed to permit the exercise of Federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.[51]

34. The Commission also proposed to require transmission providers to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[52] The Commission proposed to require transmission providers to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be ''right-sized'' to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning.[53]

35. The Commission further proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the 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.[54] Finally, the Commission proposed to require transmission providers in neighboring transmission planning regions to 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.[55]

E. High-Level Overview of NOPR Comments

36. The Commission received a great many comments from a diverse set of parties in response to the NOPR.[56] One hundred and ninety-six parties, including Federal agencies, state regulatory commissions, state policy makers and other state representatives, ratepayer advocates, municipalities, RTOs/ISOs, RTO/ISO market monitors, transmission providers, transmission-dependent utilities, electric cooperatives, municipal power providers, independent power producers, transmission developers, generation trade associations, transmission trade associations, industry interest groups, consumer interest groups, energy policy and law interest groups, individual businesses, landowners, and individuals, filed initial comments that totaled over 15,000 pages with attachments. A similarly diverse set of 92 parties filed reply comments that totaled nearly 1,900 pages.

F. Use of Terms

37. Before turning to the detailed requirements of this final order, we note several of the key terms used herein. We further address the definitions of these terms, including any modifications to definitions proposed in the NOPR, in the relevant later sections of this final order.

38. For purposes of this final order, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

39. For purposes of this final order, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final order, running

[45] *Id.* P 241.
[46] *Id.* P 272.
[47] *Id.* P 302.
[48] *Id.* P 303.
[49] *Id.* P 326.
[50] *Id.* P 333.
[51] *Id.* P 351.
[52] *Id.* P 400.
[53] *Id.* P 403.
[54] *Id.* P 427.
[55] *Id.* P 428.
[56] *See* appendix A for a list of commenters and the abbreviated names of commenters that are used in this final order.

scenarios and considering the enumerated categories of factors.[57]

40. For purposes of this final order, Long-Term Scenarios are scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs.

41. For purposes of this final order, a Long-Term Regional Transmission Facility is a regional transmission facility [58] that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.

42. For purposes of this final order, best available data inputs are data inputs that are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000, and reflect the list of factors that transmission providers account for in their Long-Term Scenarios.

43. For purposes of this final order, a Long-Term Regional Transmission Cost Allocation Method is an *ex ante* regional cost allocation method for one or more selected Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation.

44. For purposes of this final order, a Relevant State Entity is any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.

45. For purposes of this final order, a State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected.

46. For purposes of this final order, federally-recognized Tribes are those Tribes listed in the most recent notice provided by the Bureau of Indian Affairs and published in the **Federal Register**.[59]

II. The Overall Need for Reform

A. NOPR Proposal

47. The Commission issued the NOPR on April 21, 2022, proposing to reform the *pro forma* OATT and the *pro forma* LGIA to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements. The Commission stated that, over the last 25 years, it has undertaken a series of significant reforms to ensure that transmission planning and cost allocation processes result in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.[60] The Commission noted that it has now been more than a decade since Order No. 1000—its last significant regional transmission planning and cost allocation rule—and that there is mounting evidence that its regional transmission planning and cost allocation requirements may be inadequate to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.[61]

48. The Commission found that, in particular, although transmission providers are required to participate in regional transmission planning and cost allocation processes under Order No. 1000, it was concerned that those processes may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand. The Commission stated that, as a result, the regional transmission planning and cost allocation processes that transmission providers adopted to comply with Order No. 1000 may not be identifying the more efficient or cost-effective transmission facilities.[62] The Commission stated that it was concerned that the absence of sufficiently long-term, forward-looking, comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs, and that continuing with the status quo approach may cause transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. The Commission stated that this dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential. Based on the evidence, the Commission preliminarily concluded that revisions to its existing transmission planning and cost allocation requirements established in Order Nos. 890 and 1000 are necessary to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory and preferential.[63]

B. Comments

49. A significant majority of commenters, including transmission providers, transmission developers, transmission customers, members of Congress, states, state commissions, consumer advocates, trade associations, and public interest organizations, among others, agree that existing regional transmission planning and cost allocation processes need to be reformed.[64] Advanced Energy Buyers

[57] Further discussion on Long-Term Transmission Needs can be found below. *Infra* Development of Long-Term Scenarios subsection under the Long-Term Regional Transmission Planning section.

[58] For purposes of this final order, and consistent with Order No. 1000, a regional transmission facility is a transmission facility located entirely in one transmission planning region. An interregional transmission facility is a transmission facility that is located in two or more transmission planning regions. A local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation. Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 482 n.374.

[59] *See, e.g., Indian Entities Recognized by and Eligible to Receive Servs. from the U.S. Bureau of Indian Affairs,* **Federal Register**, 89 FR 944 (Jan. 8, 2024).

[60] NOPR, 179 FERC ¶ 61,028 at P 24.

[61] *Id.*

[62] *Id.* PP 24–25.

[63] *Id.* PP 25, 27, 34–35.

[64] *See, e.g.,* Acadia Center and CLF Initial Comments at 1–2; ACEG Initial Comments at 11–12, 21–22; ACORE Initial Comments at 2–5; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 2–3; AEE Initial Comments at 7–8; AEP Initial Comments at 1–3; Amazon Initial Comments at 1–2; Ameren Initial Comments at 1–2; American Municipal Power Initial Comments at 4; Anbaric Initial Comments at 1; Arizona Commission Initial Comments at 3–4; Avangrid Initial Comments at 5–6; BP Initial Comments at 3; Breakthrough Energy Initial Comments at 5–6; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2–3; California Commission Initial Comments at 1–2; California Energy Commission Initial Comments at 1; CAISO Initial Comments at 1; City of New Orleans Council Initial Comments at 4, 7–9; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 4–5; US Senators Supplemental Comments at 1; EEI Initial Comments at 4–5; ELCON Initial Comments at 4; Enel Initial Comments at 2, 7; ENGIE Initial Comments at 1–2; Entergy Initial Comments at 2–3; Environmental Legislators Caucus Supplemental Comments at 1; Evergreen Action Initial Comments at 1–3; Eversource Initial Comments at 1–2, 5–9; Exelon

Continued

note that the electric system is presently undergoing one of the most significant transformations in a century.[65] Other commenters agree that electric energy supply and demand is evolving quickly.[66] Clean Energy Buyers agree with the Commission that there is a need for reform to meet these drastic changes in the resource mix and load and to ensure continued reliability and cost-effective transmission service.[67]

50. Many commenters argue that current regional transmission planning and cost allocation processes across the country are not ensuring efficient and cost-effective transmission development, are not satisfying the purposes of Order Nos. 890 and 1000, and are not meeting transmission needs at a reasonable cost. For example, several commenters assert that Order Nos. 890 and 1000 have not solved longstanding problems with regional transmission planning and cost allocation.[68] Northwest and Intermountain claim that Order No. 1000 has been inadequate to meet transmission needs, particularly in the non-RTO/ISO West.[69] Michigan State Entities assert that the current lack of long-term transmission planning has led to significantly higher costs for residential ratepayers, costs that will increase without reforms.[70] SREA argues that reform is needed to correct the unintended consequences of Order No. 1000 in the Southeast, where transmission planning ''has grown into an enormously elaborate and extremely expensive black box,'' without any meaningful review by state regulatory bodies.[71]

51. PIOs assert that transmission owners can evade Order No. 1000 requirements through investments in local transmission projects, which has led to billions of dollars in excessive costs.[72] PIOs explain that financial incentives drive utilities to upgrade their own systems at the expense of building a more integrated and robust transmission system to meet the needs and demands of the future.[73] PIOs observe that, between 2013 and 2017, about one-half of the approximately $70 billion in aggregate transmission investments by Commission-jurisdictional transmission owners in RTO/ISO regions were approved outside of regional transmission planning processes or with limited stakeholder engagement.[74] Ohio Consumers add that since 2017, less than 25% of new transmission investments in Ohio have been associated with large regional transmission projects needed for reliability or economic efficiency.[75] Competition Coalition argues that incumbent transmission owners have used reliability designations to justify projects with higher costs.[76]

52. Citing to a report from Lawrence Berkeley National Laboratory, US DOE concludes that many existing regional transmission planning approaches are likely understating the economic value of new transmission. US DOE suggests that the need for increased transmission capacity to address persistent and worsening transmission congestion demonstrates that these processes may not fully anticipate present and future transmission needs.[77] In addition, US DOE notes the unfair burden on interconnection customers that must bear increasing costs, especially for interconnection-related network upgrades that provide system-wide benefits.[78] US DOJ and FTC agree that reforms are necessary to encourage needed regional and interregional transmission investment and that a larger, more integrated transmission system would improve resilience, promote competition, and lower costs for consumers.[79]

53. Many commenters contend that inadequate regional transmission planning and cost allocation processes have resulted in, or are threatening to cause, unjust, unreasonable, and unduly discriminatory or preferential rates.[80] Michigan State Entities cite renewable energy curtailments, which limit the supply of energy that customers can access, and the lack of regional and interregional transmission lines, which limit the transfer of lower-priced power.[81] New Jersey Commission asserts that better transmission planning

Initial Comments at 1–2; Grid United Initial Comments at 1–2; Handy Law Initial Comments at 1–7; Harvard ELI Initial Comments at 1; Illinois Commission Initial Comments at 3; Indicted PJM TOs Initial Comments at 1–2; Indicated US Senators and Representatives Initial Comments at 1; Interwest Initial Comments at 2–3; Invenergy Initial Comments at 2, 5; ISO–NE Initial Comments at 2, 8–9; ISO/RTO Council Initial Comments at 2; Kansas Commission Initial Comments at 10–11; Massachusetts Attorney General Initial Comments at 3–6; Michigan Commission Initial Comments at 2, 4; Michigan State Entities Initial Comments at 3–4; Minnesota State Entities Initial Comments at 2–3; National Grid Initial Comments at 1, 6; National and State Conservation Organizations Initial Comments at 1; NESCOE Initial Comments at 2, 7, 14–15; New Jersey Commission Initial Comments at 1–2; New York Commission and NYSERDA Initial Comments at 1–3; NextEra Reply Comments at 1; Non-RTO NASUCA Initial Comments at 4–5; NYISO Initial Comments at 2–3; Onward Energy Initial Comments at 1–2; Ørsted Initial Comments at 2–3; Pattern Energy Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 2, 7–8; Pacific Northwest State Agencies Initial Comments at 1, 8; PG&E Initial Comments at 1; PIOs Initial Comments at 6–7; Policy Integrity Initial Comments at 1–2; Renewable Northwest Initial Comments at 3–4; RMI Supplemental Comments at 1–2; SPP Market Monitor Initial Comments at 3–4; SEIA Initial Comments at 2; Shell Initial Comments at 1, 9; US Senator Barrasso Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2; Southeast PIOs Initial Comments at 1; SREA Initial Comments at 1; State Officials Supplemental Comments at 1; TAPS Initial Comments at 1–2; US DOE Initial Comments at 1–4; US DOJ and FTC Initial Comments 1, 5; Vermont State Entities Initial Comments at 2; Western State Representatives Initial Comments at 3–4; WIRES Initial Comments at 2, 5.

[65] Advanced Energy Buyers Initial Comments at 2.

[66] *See, e.g.,* AEE Initial Comments at 1; Cross Sector Representatives Supplemental Comments at 1; Eversource Initial Comments at 5–8 (citing ISO–NE, *2020 Regional Electricity Outlook,* at 35 (2020)); Indicated PJM TOs Initial Comments at 1–2; Kansas Commission Initial Comments at 2; Pattern Energy Initial Comments at 1; PG&E Initial Comments at 1; Policy Integrity Initial Comments at 2; Renewable Northwest Initial Comments at 5; State Agencies Initial Comments at 12–13; WIRES Initial Comments at 3.

[67] Clean Energy Buyers Initial Comments at 7.

[68] *See, e.g.,* Acadia Center and CLF Initial Comments at 1; ACEG Initial Comments at 17–18, 20 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3; NOPR, 179 FERC ¶ 61,028 at PP 24–25); AEE Initial Comments at 1–2; CARE Coalition Initial Comments at 3; NERC Initial Comments at 5; Massachusetts Attorney General Initial Comments at 5–6; Northwest and Intermountain Initial Comments at 6–7; Pine Gate Initial Comments at 8–10; PIOs Initial Comments at 2–3; Southeast PIOs Initial Comments at 7–9, 11, 16–17, 43–44; SPP Market Monitor Initial Comments at 3–4; SREA Reply Comments at 4; US DOE Initial Comments at 3–4, 7–8.

[69] Northwest and Intermountain Initial Comments at 6–7.

[70] Michigan State Entities Initial Comments at 1–2.

[71] SREA Reply Comments at 4.

[72] PIOs Initial Comments at 8 (citing Johannes P. Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value,* at 19–20, and Section I (Apr. 2019) (Brattle Apr. 2019 Competition Report), *https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf*).

[73] *Id.* at 6–7.

[74] *Id.* at 9 (citing Brattle Apr. 2019 Competition Report at 4).

[75] Ohio Consumers Initial Comments at 5.

[76] Competition Coalition Initial Comments at 15–16.

[77] US DOE Initial Comments at 3–4.

[78] *Id.* at 7–8.

[79] US DOJ and FTC Initial Comments at 1, 5 (citing NOPR, 179 FERC ¶ 61,028 at P 6; P. R. Brown & A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System,* 5 Joule 115, 115–134 (2021); Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* at 108 (Oct. 2021), *https://netzeroamerica.princeton.edu/the-report*).

[80] *See, e.g.,* ACORE Initial Comments at 3, AEE Initial Comments at 27 (citing NOPR, 179 FERC ¶ 61,028 at PP 47, 55, 78; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56); CARE Coalition Initial Comments at 17; Certain TDUs Initial Comments at 2; Clean Energy Associations Initial Comments at 3, 7; Clean Energy Buyers Initial Comments at 10; Harvard ELI Initial Comments at 1; Massachusetts Attorney General Initial Comments at 5–6; New Jersey Commission Initial Comments at 1–2; PIOs Initial Comments at 6; SEIA Initial Comments at 2–3; Southeast PIOs Reply Comments at 2; US DOE Initial Comments at 2, 6–7.

[81] Michigan State Entities Initial Comments at 3.

can reduce overall system costs by billions of dollars.[82] Certain TDUs add that Commission action is essential now to ensure that necessary transmission expansion occurs in a way that protects customers from excessive costs and that results in just and reasonable transmission rates.[83] CARE Coalition argues that the Commission's current failure to require transmission planners to internalize siting-related costs and risks results in unjust, unreasonable, and unduly discriminatory or preferential rates.[84] In a similar vein, Ørsted and Massachusetts Attorney General claim that failure to proactively plan for offshore wind generation buildout could lead to transmission rates that are unjust, unreasonable, and unduly discriminatory or preferential.[85]

54. Several commenters agree with the Commission's concerns that the expansion of the high-voltage transmission system is increasingly occurring outside of the regional transmission planning process through other mechanisms such as the generator interconnection process, which results in piecemeal transmission development.[86] AEE agrees that limited development of regional transmission facilities, increased spending on local transmission projects, and backlogged interconnection queues all show that the existing regional transmission planning requirements are not sufficient to meet customers' transmission needs.[87] Likewise, Exelon argues that relying on interconnection studies as the primary transmission planning method results in piecemeal and inefficient transmission investment.[88] PIOs add that many generation developers have to bear the full costs of transmission upgrades, which leads to interconnection request withdrawals, inefficiencies, and higher system-wide costs.[89] In addition, Clean Energy States note that interconnection queues are extremely large and that the current one-plant-at-a-time approach to transmission upgrades drives up costs and misses opportunities for improvements to the system as a whole.[90]

55. Non-RTO NASUCA agrees with the Commission that Long-Term Regional Transmission Planning is necessary to help alleviate generation interconnection issues.[91] According to Harvard ELI, current transmission planning processes have failed to address backlogged interconnection queues and operational challenges that are best addressed at the regional level, as well as to include inexpensive technologies that can increase transmission capacity.[92]

56. ACEG argues that there is no evidence that any regional reliability or economic transmission planning performed in non-RTO/ISO regions, like the Southeastern Regional Transmission Planning region (SERTP), is equal to or superior to the techniques or outcomes in the NOPR.[93] ACEG further contends that, instead, most new transmission facilities built since Order No. 1000 have been built for local transmission needs, thereby resulting in less efficient and cost-effective transmission development that does not address the larger needs of the transmission system for reliability and resilience.[94] Relatedly, SREA states that no state fully participates in SERTP, and that instead, each state in the Southeast uses its own state planning process, with no platform for states to collaborate. As a result, SREA argues that ''transmission planning in the Southeast has many holes and is threadbare.'' [95] SREA catalogs deficiencies in many Southeastern states' planning processes, including a lack of transparency.[96]

57. Western PIOs argue that, outside of CAISO, transmission planning in the West is ineffective.[97] Specifically, Western PIOs assert that Western transmission planning groups have not developed new transmission projects using their Order No. 1000 transmission planning processes, but have instead built transmission projects that their utility members have already proposed.[98] Relatedly, SEIA argues that ''non-RTO areas do not engage in sufficient or transparent transmission planning,'' and that transmission planning in non-RTO/ISO regions is exclusionary, based on inconsistent and inaccurate data, and disjointed.[99] More broadly, NRECA contends that incumbent investor-owned utilities control transmission planning, and that some incumbent investor-owned utilities develop transmission without transparency, leading to disparities in transmission rates in different RTO/ISO local zones.[100]

58. Several commenters specify other reasons that transmission planning reforms are needed.[101] Americans for Fair Energy Prices agree with PIOs that there is a need for regional transmission planning instead of the balkanized process that currently exists.[102] DC and MD Offices of People's Counsel assert that the NOPR provides a once-in-a-generation opportunity to meet the energy transition in a just, equitable, efficient, reliable, and resilient fashion by recognizing the benefits of long-term transmission planning and developing rules that incorporate those broad benefits. DC and MD Offices of People's Counsel state that current transmission planning processes do not fully consider all of the benefits of transmission development, including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather.[103] ACEG argues that current transmission planning processes have not led to investment in interregional transmission capacity, and that more interregional transmission capacity could have avoided some of the $25 billion to $70 billion in yearly costs caused by severe weather events.[104] EEI states that robust transmission development will provide a host of benefits for customers, including greater resilience, enhanced system reliability, and cost-savings from greater access to low-cost resources.[105] Some commenters emphasize the importance of the Commission taking prudent action to remedy deficiencies in the Commission's existing regional transmission planning and cost

[82] New Jersey Commission Initial Comments at 3–9.

[83] Certain TDUs Initial Comments at 2.

[84] CARE Coalition Initial Comments at 17.

[85] Massachusetts Attorney General Initial Comments at 5; Ørsted Initial Comments at 3–5.

[86] *See, e.g.,* Acadia Center and CLF Initial Comments at 3–4; Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 4–7; Exelon Initial Comments at 1–2, 5; Joint Consumer Advocates Initial Comments at 5; Non-RTO NASUCA Initial Comments at 4; Ørsted Initial Comments at 4–5; Pine Gate Initial Comments at 8–10; SEIA Initial Comments at 2; *see also* AEP Initial Comments at 8.

[87] AEE Initial Comments at 1–2 (citing NOPR, 179 FERC ¶ 61,028 at PP 47–55).

[88] Exelon Initial Comments at 5.

[89] PIOs Initial Comments at 9–10.

[90] Clean Energy States Initial Comments at 2.

[91] Non-RTO NASUCA Initial Comments at 4.

[92] Harvard ELI Initial Comments at 1.

[93] ACEG Reply Comments at 9 (citing Alabama Commission Initial Comments at 2–3; Southern Initial Comments at 5–6, Ex. 2 at 2–3).

[94] *Id.* at 9–10 (citing PIOs Initial Comments at 7).

[95] SREA Reply Comments at 4.

[96] *Id.* at 5–18.

[97] Western PIOs Initial Comments at 4–28.

[98] *Id.* at 28.

[99] SEIA Reply Comments at 5–6 (citing Southern Initial Comments at 13–14).

[100] NRECA Initial Comments at 15–16.

[101] *See, e.g.,* Americans for Fair Energy Prices Reply Comments at 5; SREA Reply Comments at 4.

[102] Americans for Fair Energy Prices Reply Comments at 5 (citing PIOs Initial Comments at 34).

[103] DC and MD Offices of People's Counsel Reply Comments at 1–2.

[104] ACEG Initial Comments at 21–22 (citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather,* at 1–3, 12 (July 2021) (Grid Strategies July 2021 Extreme Weather Report)).

[105] EEI Supplemental Comments at 1.

allocation requirements,[106] and to strengthen electric reliability and resilience, while controlling costs.[107]

59. Several commenters argue that the need to reform transmission planning includes addressing environmental justice and equity issues.[108] Center for Biological Diversity states that energy justice and environmental justice considerations are appropriately included in transmission planning.[109] Center for Biological Diversity further asserts that it is within the Commission's authority to consider these costs and benefits, as the benefits of decarbonization and related energy justice objectives will be far greater than the costs.[110] Grand Rapids NAACP, CARE Coalition, and PIOs argue that to ensure just, reasonable, and nondiscriminatory rates, transmission planning must consider energy equity and environmental justice.[111] Grand Rapids NAACP further argues that high energy burdens can be unjust, unreasonable, and unduly discriminatory or preferential.[112] Grand Rapids NAACP argues that the Commission's duty under the FPA to promote the public interest requires it to ensure that energy justice and equity considerations are included in transmission planning processes.[113] WE ACT relatedly argues that, due to under-investment, the transmission system is unreliable and vulnerable to extreme weather events, which is both a reliability and environmental justice issue because communities of color and low-income communities are more susceptible to power outages during extreme weather.[114]

60. Advanced Energy Buyers state that failure to prepare the grid for the energy transition would be problematic for three primary reasons: (1) insufficient transmission investment will leave customer cost savings on the table; (2) lack of available transmission capacity will constrain its members' ability to meet decarbonization and clean energy goals; and (3) failure to plan and build adequate transmission will hamper the transition to a cleaner and more reliable electric grid.[115] New Jersey Commission contends that the lack of holistic multi-driver transmission planning is inflating consumers' electricity costs by billions of dollars every year.[116] Northwest and Intermountain explain that due to insufficient transmission capacity from renewable rich zones, utilities must attempt to meet their renewable energy policy targets with new resources that are close to load but more expensive, less reliable, and less efficient than more distant alternatives, even considering the potential costs of transmission expansion.[117] Clean Energy Associations add that the lack of transmission capacity imposes real and demonstrable costs today, as evidenced by geographic differences in real-time power prices, and that the lack of robust and proactive transmission planning rules renders current rates unjust, unreasonable, and unduly discriminatory or preferential.[118]

61. Southeast PIOs contend that the ''snowballing'' inefficiencies created by numerous small-scale transmission ''band-aids'' result in unjust, unreasonable, and unduly discriminatory or preferential rates, and that reforms are particularly needed in the Southeast, where there is minimal utility coordination and a balkanized transmission system.[119] According to ACEG, short-term, piecemeal transmission planning is unlikely to identify the more efficient or cost-effective solutions to transmission needs and thus will result in unjust, unreasonable, and unduly discriminatory or preferential rates.[120]

62. Many commenters argue that reforms are necessary to meet state policy goals[121] and that greater state involvement or consideration of state policies is needed to avoid transmission planning inefficiencies.[122] For example, ACORE cites a recent National Renewable Energy Laboratory (NREL) report highlighting the need for new transmission to aid in achieving zero carbon goals.[123] NextEra opines that the passage of the Inflation Reduction Act of 2022 will increase the demand for renewables and drive corresponding demands on the transmission system.[124] Pacific Northwest State Agencies argue that reforms are critical to successfully achieving their respective state clean energy laws and policies and to ensuring that there is sufficient clean, safe, reliable, and affordable energy.[125] Michigan State Entities note that some states may pursue aggressive renewable energy portfolio standards, and others may have no such requirements, but these policy choices will inevitably affect the price and reliability of energy for all customers across the states in question and that not planning for that reality imposes costs on unwilling customers.[126]

[106] US Senators Supplemental Comments at 1; Senator Whitehouse Supplemental Comments at 2.

[107] US Senator Barrasso Supplemental Comments at 1–2.

[108] *See, e.g.,* CARE Coalition Initial Comments at 2; Center for Biological Diversity Initial Comments at 20–24; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Grand Rapids NAACP Initial Comments at 20–21; Massachusetts Attorney General Initial Comments at 53–54 (citing Massachusetts Attorney General ANOPR Initial Comments at 32–34); Montclair Congregation Supplemental Comments at 1; NESCOE Reply Comments at 8–9; New England for Offshore Wind Initial Comments at 5; PIOs Reply Comments at 11–17; US DOE Initial Comments at 9; WE ACT Initial Comments at 1–2.

[109] Center for Biological Diversity Initial Comments at 20–24 (citing Pacific Northwest National Laboratory & Sandia National Laboratories, *Advancing Energy Equity in Grid Planning* (Apr. 2022), *https://netl.doe.gov/sites/default/files/netl-file/Advancing%20Energy%20Equity%20in%20Grid%20Planning.pdf*; Office of Energy Justice and Equity, US DOE, *Justice40 Initiative, https://www.energy.gov/diversity/justice40-initiative*).

[110] *Id.* at 23 (citing *Neb. Pub. Power Dist.* v. *FERC,* 957 F.3d 932, 942 (8th Cir. 2020)).

[111] Grand Rapids NAACP Reply Comments at 4 (citing 16 U.S.C. 824(a); *Re Nat'l Ass'n for the Advancement of Colored People, Inc.,* 95 P.U.R.3d 357 (F.P.C. 1972), *vacated and remanded sub nom. NAACP* v. *FPC,* 520 F.2d 432 (D.C. Cir. 1975), *aff'd,* 425 U.S. 662 (1976)); CARE Coalition Initial Comments at 2; PIOs Reply Comments at 14.

[112] *Id.* at 20–21.

[113] *Id.* at 17–19.

[114] WE ACT Initial Comments at 1–2.

[115] Advanced Energy Buyers Initial Comments at 3.

[116] New Jersey Commission Initial Comments at 2–9.

[117] Northwest and Intermountain Initial Comments at 6.

[118] Clean Energy Associations Initial Comments at 5 (citing Dev Millstein et al., Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value Using Locational Marginal Prices,* at 3 (Aug. 2022), *https://eta-publications.lbl.gov/sites/default/files/lbnlempirical_transmission_value_study-august_2022.pdf* (LBNL Aug. 2022 Transmission Value Study)).

[119] Southeast PIOs Reply Comments at 1–2.

[120] ACEG Initial Comments at 21.

[121] *See, e.g.,* Acadia Center and CLF Initial Comments at 1; ACORE Reply Comments at 1; Breakthrough Energy Initial Comments at 5–6; Business Council for Sustainable Energy Initial Comments 2–3; Illinois Commission Initial Comments at 3–4; ISO–NE Initial Comments at 2; Michigan State Entities Initial Comments at 2–3; National Grid Initial Comments at 6–7; NESCOE Initial Comments at 9–10, 15–16; NextEra Reply Comments at 5, 25; Northwest and Intermountain Initial Comments at 5–6; Ørsted Initial Comments at 1–3; Pacific Northwest State Agencies Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 10–11; State Agencies Initial Comments at 16–17; Vermont Electric and Vermont Transco Initial Comments at 2; Western State Representatives Initial Comments at 3.

[122] *See, e.g.,* AEE Reply Comments at 3–4; California Democratic Representatives Supplemental Comments at 1–2; US Senators Supplemental Comments at 1 (citing to National Academies of Sciences, Engineering, and Medicine, *Accelerating Decarbonization in the United States: Technology, Policy, and Societal Dimensions* (2023)); Maryland Energy Admin Initial Comments at 1; North Carolina Commission and Staff Initial Comments at 2, 4; PJM States Initial Comments at 1; SREA Reply Comments at 4.

[123] ACORE Reply Comments at 1 (citing Paul Denholm, et al., NREL, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (Sept. 2022), *https://www.nrel.gov/docs/fy22osti/81644.pdf*).

[124] NextEra Reply Comments at 5, 25.

[125] Pacific Northwest State Agencies at 1.

[126] Michigan State Entities Initial Comments at 2–3.

63. PacifiCorp and NV Energy similarly assert that the need for reform in the West is driven by the diverse policy priorities in its six-state transmission system, and they note that decisions are subject to state oversight and the participation of disparately situated transmission providers without inclination or authority to accept any cost allocation.[127] National Grid asserts that ISO New England's (ISO–NE) 2050 Transmission Study demonstrates a direct connection between state laws and requirements to meet clean energy goals and the need for new and expanded transmission facilities.[128] Indicated PJM TOs add that maintaining a reliable and resilient transmission system requires forward-looking assessments informed by evolving public policy, changing generation mix and demand patterns, and stakeholder input.[129]

64. Maryland Energy Administration contends that Maryland has experienced unfair and costly consequences of inadequate consultation with state authorities in regional transmission planning processes.[130] AEE argues that if current transmission planning processes fail to incorporate factors such as state laws, corporate targets, and retail demand, then transmission needs will be unmet, risking unjust, unreasonable, and unduly discriminatory or preferential rates.[131]

65. Many commenters argue that, based on the record, the Commission has an obligation under the FPA to take action to ensure that transmission planning and cost allocation results in rates that are just and reasonable and not unduly discriminatory.[132] ACEG states that the Commission's broad authority to remedy unduly discriminatory behavior pursuant to FPA section 206 applies to transmission planning and cost allocation, as the U.S. Court of Appeals for the District of Columbia Circuit held in *South Carolina Public Service Authority* v. *FERC*.[133] PIOs contend that the Commission is required by the FPA to use its authority to address market abuses and undue discrimination that have led to unjust, unreasonable, and unduly discriminatory or preferential rates for consumers, who bear the costs of inefficiencies in the current transmission planning process.[134]

66. Southeast PIOs assert that the NOPR adequately demonstrated that existing regional transmission planning processes have intrinsic flaws, making the integrated resource planning and request for proposal processes ill-equipped to efficiently address changes in the resource mix and demand.[135] Specifically, Southeast PIOs cite the following preliminary findings from the NOPR: (1) existing transmission planning processes utilize a limited planning horizon; (2) many transmission planning processes provide an inaccurate portrayal of the comparative benefits of different transmission facilities; and (3) rapid changes to the generation fleet and demand are creating increasingly urgent transmission needs.[136]

67. Southeast PIOs cite the finding in *South Carolina Public Service Authority* v. *FERC* that the threshold of substantial evidence could be met without ''empirical evidence'' as long as the Commission provides evidence based on ''reasonable economic propositions.'' [137] Southeast PIOs also note that *South Carolina Public Service Authority* v. *FERC* upheld the Commission's findings in Order No. 1000, which were based on (1) a threat to just and reasonable rates from existing regional transmission planning and cost allocation practices, (2) significant changes in the industry driven by increases in renewable energy resources, and (3) recent increases in transmission investment.[138] Moreover, Southeast PIOs note that findings need not be region-specific, as the ''Commission may rely on generic or general findings of a systemic problem to support imposition of an industry-wide solution.'' [139]

68. ACEG similarly asserts that the Commission has shown the need for transmission planning reform based on findings that existing transmission planning requirements do not adequately identify transmission needs driven by changes in the resource mix and demand, and that failure to identify such needs causes customers to pay for less efficient or cost-effective transmission investments.[140] Relatedly, ACEG argues that pursuing region-specific solutions will lead to siloed and disjunctive transmission planning policies that will not solve the problems facing the Nation's electric transmission system.[141]

69. Colorado Consumer Advocate and Joint Consumer Advocates aver that the Commission has a statutory duty under the FPA to reform current regional transmission planning processes because they lack transparency, coordination, and openness, and because they create opportunities for monopoly transmission developers to exert dominant influence and promote their own economic self-interest at customers' and other stakeholders' expense.[142] According to New Jersey Commission, current transmission planning processes are inefficient and unnecessarily burden ratepayers with excessive costs without providing additional benefits. New Jersey Commission contends that those processes are therefore per se unjust and unreasonable, and that the Commission thus has FPA section 206 authority to require that transmission providers employ practices like long-term, holistic, multi-driver transmission planning.[143]

70. Similarly, Harvard ELI states that deficient transmission planning threatens the justness and reasonableness of transmission rates, and therefore the Commission has legal authority and jurisdiction to order changes to transmission planning to remedy that deficiency.[144] Harvard ELI further asserts that the Commission must remedy undue discrimination due to incumbent transmission owners' unduly discriminatory influence in regional transmission planning.[145] Massachusetts Attorney General also

[127] PacifiCorp and NV Energy Initial Comments at 10–11.

[128] National Grid Initial Comments at 6–7 (citing the then-preliminary findings from the ISO–NE 2050 Transmission Study).

[129] Indicated PJM TOs Initial Comments at 1.

[130] Maryland Energy Administration Initial Comments at 1 (citing Maryland Energy Administration ANOPR Initial Comments at 2).

[131] AEE Reply Comments at 3–4.

[132] *See, e.g.,* ACEG Initial Comments at 11; Clean Energy Associations Initial Comments at 7–10; Grand Rapids NAACP Initial Comments at 17; Massachusetts Attorney General Initial Comments at 3–4; Pine Gate Initial Comments at 10–14; PIOs Initial Comments at 8.

[133] 762 F.3d at 57. *See also* ACEG Initial Comments at 13–14; Harvard ELI Initial Comments at 1–2; SEIA Initial Comments at 3.

[134] PIOs Initial Comments at 8.

[135] Southeast PIOs Reply Comments at 4 (citing Duke Initial Comments at 6–9; SERTP Sponsors Initial Comments at 31–36; Southern Initial Comments at 36–40).

[136] *Id.* at 5–6 (citing NOPR, 179 FERC ¶ 61,028 at PP 45, 47, 49, 53).

[137] *Id.* at 6–7 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 65).

[138] *Id.* at 6–7 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 65–66).

[139] *Id.* at 7 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67).

[140] ACEG Reply Comments at 7–8 (citing Alabama Commission Initial Comments at 2–3; Duke Initial Comments at 6–9; Idaho Power Initial Comments at 2–3; NRECA Initial Comments at 11; North Carolina Commission and Staff Initial Comments at 14; Pacific Northwest Utilities Initial Comments at 9–10; Utah Commission Initial Comments at 9–12).

[141] *Id.* at 17.

[142] Colorado Consumer Advocate Initial Comments at 21–23; Joint Consumer Advocates Initial Comments at 18–20.

[143] New Jersey Commission Initial Comments at 3–4.

[144] Harvard ELI Initial Comments at 1–2 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41; Order No.1000–A, 139 FERC ¶ 61,132 at PP 56–75).

[145] *Id.* at 3.

argues that the Commission's proposed reforms are necessary to fulfill the Commission's statutory obligation to ensure that transmission rates are just and reasonable.[146]

71. Some commenters argue that there is insufficient evidence for the Commission to find that existing jurisdictional rates are unjust, unreasonable, and unduly discriminatory or preferential.[147] For example, while Idaho Commission recognizes that there are deficiencies in existing transmission planning and cost allocation processes, Idaho Commission disagrees with the NOPR's claim that their failure to identify and plan for transmission needs driven by changes in the resource mix and demand is resulting in unjust, unreasonable, and unduly discriminatory or preferential Commission-jurisdictional rates.[148] Mississippi Commission also disagrees that the lack of long-term regional transmission planning will result in unjust, unreasonable, and unduly discriminatory or preferential rates.[149] ELCON questions a finding of unjust, unreasonable, and unduly discriminatory or preferential rates, and it states that the NOPR's focus on Long-Term Regional Transmission Planning solely to address changes in resource mix and demand, if adopted, could fail to produce better outcomes for customers and may exceed the Commission's authority under the FPA.[150]

72. Louisiana Commission states that the Commission's finding that, absent reforms, transmission rates universally are not just and reasonable and are discriminatory is not based on individual analysis of each RTO or region, is not supported, and should be retracted.[151] Mississippi Commission also states that the Commission should, instead, initiate region-specific investigations pursuant to FPA section 206.[152] Southern argues that the Commission has failed to satisfy the first prong of its FPA section 206 burden of proof, noting that the NOPR's preliminary conclusion, that existing regional transmission planning processes are not sufficient to address changes in the resource mix and demand, cannot reasonably be made of Southern or SERTP.[153]

73. Similarly, Industrial Customers argue that the Commission has not satisfied the first prong of FPA section 206, which requires the Commission to find, and provide substantial evidence supporting its finding, that existing rates are unjust, unreasonable, and unduly discriminatory or preferential.[154] Industrial Customers claim that demand growth should be the primary factor in identifying transmission needs, and that demand is growing more slowly than in previous periods. Industrial Customers add that, in contrast, investment in transmission is rising relative to demand, which is the opposite of the circumstances that prevailed in 2007 when the Commission issued Order No. 890.[155] According to Industrial Customers, changes in demand are not significant enough in historical terms to warrant major changes in transmission planning. Moreover, Industrial Customers state that changes in demand are unpredictable because technological changes are inherently difficult to forecast and the risks to consumers of making mistakes are too high. Industrial Customers argue that, if anything, the rapid growth of renewables indicates that current processes are already facilitating changes in the resource mix.[156] Similarly, NRG argues that long-term forecasts of important factors are often wrong, which has real-world impacts on customers.[157]

74. Further, Industrial Customers contend that the NOPR does not clearly define the term ''changes in the resource mix and demand,'' despite using such changes as the justification for the proposals. Industrial Customers argue that transmission should only be planned in order to maintain reliability and should not be based on the demand for certain fuel sources or the fuel type of the generation fleet.[158] Industrial Customers argue that current transmission planning is based on known and measurable factors, and that any attempt to plan for potential future changes in the resource mix without determining precisely what these changes will be would result in the overbuilding of the system for generation that may not be built. Industrial Customers argue that this outcome would be unjust and unreasonable and would force transmission customers to pay for generation that is non-existent.[159]

75. Other commenters agree that the Commission lacks a specific record to support the need for reform.[160] For example, former Kansas Commission Chair Keen avers that there is no analytical or evidentiary basis in the NOPR for a complete and thorough overhaul or revision of transmission planning processes.[161]

76. Duke asserts that the NOPR does not provide robust and specific support as to how and why current regional transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment.[162] Duke asserts that the NOPR does not support the presumption that the absence of significant regional transmission investment is evidence of inefficient transmission planning.[163] Duke also asserts that, to ensure legal durability, the Commission should identify evidence that justifies a nationwide finding that current transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment and unjust, unreasonable, and unduly discriminatory or preferential rates.[164]

77. Undersigned States argue that the Commission does not have evidence in the record that current rates are unjust, unreasonable, or unduly discriminatory or preferential, which FPA section 206 requires.[165] Undersigned States argue

[146] Massachusetts Attorney General Initial Comments at 3–6.

[147] *See, e.g.,* ELCON Initial Comments at 7; Idaho Commission Initial Comments at 2; Mississippi Commission Initial Comments at 2, 9; NRECA Initial Comments at 14–16; Undersigned States Reply Comments at 6–7.

[148] Idaho Commission Initial Comments at 2 (citing NOPR, 179 FERC ¶ 61,028 at P 34).

[149] Mississippi Commission Initial Comments at 2.

[150] ELCON Initial Comments at 7.

[151] Louisiana Commission Reply Comments at 5–6.

[152] Mississippi Commission Reply Comments at 7–9.

[153] Southern Initial Comments at 40; Southern Reply Comments at 1–3.

[154] Industrial Customers Initial Comments at 6–7.

[155] *Id.* at 8–10.

[156] *Id.* at 10–11.

[157] NRG Initial Comments at 10–12 (noting, for example, that ''[p]redictions for the future price of natural gas and thus the economics of gas generation in long-term forecasts have been notoriously inaccurate.'' (citing Lawrence Berkeley National Laboratory, *Comparison of AEO 2008 Natural Gas Price Forecast to NYMEX Futures Prices* (Jan. 2008)).

[158] Industrial Customers Initial Comments at 7–8.

[159] *Id.* at 15.

[160] *See, e.g.,* Alabama Commission Initial Comments at 4–5; Duke Initial Comments 6–9; Idaho Commission Initial Comments at 2; Industrial Customers Initial Comments at 1, 6–11, 15; Kansas Commission Chair Keen Initial Comments at 1–2; Nebraska Commission Initial Comments at 1–2; NRECA Initial Comments at 14–16; NRG Initial Comments at 3; Ohio Commission Federal Advocate Initial Comments at 5–6; Potomac Economics Initial Comments at 3–4; Southern Initial Comments at 40.

[161] Kansas Commission Chair Keen Initial Comments at 2.

[162] Duke Initial Comments at 6–7.

[163] *Id.* at 7–8.

[164] *Id.* at 9 (citing *Emera Me.* v. *FERC,* 854 F.3d 9, 24 (D.C. Cir. 2017)).

[165] Undersigned States Reply Comments at 6–7. The Undersigned States that submitted reply comments include the States of Texas, Utah, Alabama, Alaska, Arkansas, Florida, Georgia, Kansas, Kentucky, Louisiana, Mississippi, Montana,

that, contrary to the preliminary findings in the NOPR, the Southeast has developed significant and sufficient transmission infrastructure and renewable energy from 2015–2020. Undersigned States further argue that the Commission is supposed to enhance reliability, and that, because renewables are intermittent and inherently less reliable, forcing ratepayers to subsidize their use through financing the construction of additional transmission infrastructure is not consistent with the Commission's mission. Undersigned States also argue that the Commission has not justified replacing existing transmission planning processes with a new approach, so the NOPR is arbitrary and capricious.[166] Further, Undersigned States argue that the Commission has not offered a detailed justification for countering prior precedent in Order No. 1000 that ''the regional transmission planning process is not the vehicle by which integrated resource planning is conducted.'' [167]

78. Some commenters assert that the intention of the NOPR is to improperly favor certain energy resources.[168] Consumer Organizations argue that solutions that allow for an equitable transition and make space for advancing technology and smaller energy systems are preferrable to a rushed plan that favors certain resources, such as wind, solar, and battery storage, that have already proven to be inadequate.[169] ELCON adds that Congress did not give the Commission express authority to balance the FPA's just and reasonable rates requirement with the policy goal of connecting renewable resources to the transmission system.[170] SERTP Sponsors argue that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and thereby effect particular, substantive transmission outcomes; rather, SERTP Sponsors continue, Congress has expressly and unequivocally reserved generation authority to the states.[171] Louisiana Commission argues that the FPA does not confer on the Commission authority to engage in wide-scale public policymaking by enacting sweeping energy policy changes with far-reaching, nationwide effects.[172]

79. Ohio Commission Federal Advocate states that the NOPR may be intended ''to establish policies designed to encourage the massive transmission build-out that will doubtless be required to transition to an aspirational renewable future'' and ''to achieve narrow environmental policy objectives, not to address legitimate requirements under the Federal Power Act like ensuring just and reasonable rates or reliability.'' [173] Former Kansas Commission Chair Keen claims that the NOPR encourages an extensive and expensive transmission build-out without considering the impact on state-jurisdictional generation mixes. He also claims that some of the NOPR proposals impose an accelerated pace for the transition from dispatchable to renewable resources, which could hasten the premature retirement of dispatchable generation and compromise regional and state power reliability. He also expresses concern that the NOPR proposals would force ratepayers in some states to pay for neighboring states' transmission projects to advance public policy goals that they do not share.[174]

80. Some commenters challenge aspects of the need for reform. For example, Nebraska Commission believes that the established structures in RTO/ISO regions are generally working and that many aspects of the NOPR are thus unnecessary there.[175] Potomac Economics disagrees with some of the Commission's arguments for requiring Long-Term Regional Transmission Planning, contending that the Commission's proposals are based on anticipated future generation and other speculative factors and seem to be incorrectly premised on a presumption that congestion should not exist or may limit investment in economic generation. Potomac Economics states that investment should occur only to the extent that the savings of reducing congestion are larger than the investment costs. According to Potomac Economics, congestion that is caused by generators' siting decisions should be borne by the generation developers, as it will incent them to propose the lowest-cost projects taking transmission costs into account. Potomac Economics argues that, if transmission is expanded preemptively to facilitate generation investment in a particular location, such costs are equivalent to subsidies for the developer.[176]

81. Mississippi Commission disagrees that too much expansion of high-voltage transmission has occurred through the generator interconnection process instead of through regional transmission planning.[177] Similarly, North Carolina Commission and Staff disagree with the Commission's conclusion that the growth in interconnection-related network upgrades demonstrates a failure of regional transmission planning as it relates to North Carolina.[178] Southern adds that, contrary to statements in the NOPR, it is not significantly expanding its transmission system through the generator interconnection process.[179]

82. Alabama Commission asserts that Alabama has a resource planning process that accounts for needed transmission buildout to maintain reliable service, and thus, Alabama Power plans its transmission system proactively both to maintain deliveries from existing resources and to accommodate Alabama Commission-certified generation additions. Alabama Commission claims that the SERTP process builds on the integrated resource planning efforts of its sponsor states, ensuring that there are no regional transmission solutions that are more efficient or cost-effective than solutions identified through the underlying state-jurisdictional processes.[180]

83. Duke argues that, for certain transmission providers, the local transmission planning process may more effectively meet transmission needs, especially when combined with state-regulated integrated resource planning and a bottom-up regional transmission planning process. Duke contends that a regional transmission facility may not fully address local transmission needs such that a local transmission facility would still be needed, and thus, the regional transmission facility is not necessarily more efficient or cost-effective than the local transmission facility.[181]

Nebraska, Ohio, Oklahoma, South Carolina, and West Virginia. *Id.* at 1. The Undersigned States that submitted initial comments include the States of Utah, Alaska, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Texas, West Virginia, and Wyoming. Undersigned States Initial Comments at 5–6.

166 Undersigned States Reply Comments at 6–8.

167 *Id.* at 8 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

168 *See, e.g.,* Consumers Organizations Initial Comments at 1–3; ELCON Initial Comments at 9–10.

169 Consumers Organizations Initial Comments at 1–3.

170 ELCON Initial Comments at 9–10 (citing 16 U.S.C. 824q(b)(4)).

171 SERTP Sponsors Initial Comments at 18.

172 Louisiana Commission Initial Comments at 6 (citing *West Virginia* v. *EPA,* 597 U.S. 697 (2022)).

173 Ohio Commission Federal Advocate Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028, Danly, Comm'r, dissenting, at PP 2–3).

174 Kansas Commission Chair Keen Initial Comments at 3.

175 Nebraska Commission Initial Comments at 1–2.

176 Potomac Economics Initial Comments at 3–4.

177 Mississippi Commission Initial Comments at 9.

178 North Carolina Commission and Staff Initial Comments at 5.

179 Southern Initial Comments at 38–40.

180 Alabama Commission Initial Comments at 4.

181 Duke Initial Comments at 7–9.

84. NRECA states that certain of its members in RTOs/ISOs believe that regional transmission planning is working well to meet long-term needs (*e.g.,* those in MISO) and that the NOPR proposals would burden transmission providers' limited resources. NRECA states that other NRECA members in RTOs/ISOs believe that existing RTO/ISO transmission planning processes contain discrete deficiencies that the NOPR proposals will not remedy. According to NRECA, these electric cooperatives believe that some incumbent investor-owned transmission owners develop local transmission projects without transparency concerning need or costs, leading to disparities in transmission rates across RTO/ISO transmission zones, and that incumbent transmission owners control the transmission planning process such that no regional transmission planning occurs. NRECA states that, in these cooperatives' view, the criteria to determine the eligibility of a regional transmission project is the barrier, and that requiring Long-Term Regional Transmission Planning, by itself, will not solve the problem.[182]

C. Commission Determination

85. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements is causing transmission providers to fail to adequately anticipate and plan for future system conditions. It causes transmission providers to fail to appropriately evaluate the benefits of transmission infrastructure, and results in piecemeal transmission expansion to address relatively near-term transmission needs. We find that this status quo causes transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than necessary or appropriate to meet their transmission needs and forgoing benefits that outweigh their costs, which results in less efficient or cost-effective transmission investments. As explained below, we find that these deficiencies render Commission-jurisdictional regional transmission planning and cost allocation processes unjust, unreasonable, and unduly discriminatory or preferential.

86. The Commission has authority under FPA section 206 to issue this final order. Specifically, FPA section 206 ''instructs the Commission to remedy 'any . . . practice' that 'affect[s]' a rate for interstate electricity service 'demanded' or 'charged' by 'any public utility' if such practice is 'unjust, unreasonable, unduly discriminatory or preferential.''' [183] As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction.[184] As the Court explained in *South Carolina Public Service Authority* v. *FERC,* transmission providers use those processes to ''determine which transmission facilities will more efficiently or cost-effectively meet'' transmission needs, the development of which directly impacts the rates, terms, and conditions of Commission-jurisdictional service.[185] In particular, because these processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates, we find that they directly affect those rates.[186] In addition, as discussed below, such transmission facilities contribute to the development of a more robust transmission system, supporting continuity of service in the face of growing reliability challenges and providing wholesale electric customers greater access to lower-cost generation supplied by a wider range of resources. Accordingly, regional transmission planning and cost allocation processes, as well as ''the rules and practices that determine how those [processes] operate,''[187] have a direct effect on the rates that customers pay for *both* the transmission and sale of electric energy in interstate commerce.[188] The Commission may act pursuant to FPA section 206 if the Commission first establishes, through substantial evidence,[189] that the existing practices are unjust, unreasonable, or unduly discriminatory or preferential and, second, establishes that the replacement practices are just and reasonable.[190]

87. With regard to the first showing under FPA section 206, we find that, while Order No. 890 requires transmission providers to satisfy certain principles in their local transmission planning processes and Order No. 1000 requires transmission providers to participate in regional transmission planning and cost allocation processes that satisfy the requirements set forth therein, these existing transmission planning and cost allocation requirements do not result in regional transmission planning that is conducted on a sufficiently long-term, forward-looking, and comprehensive basis to plan for Long-Term Transmission Needs. As a result, we find that transmission providers are often not identifying, evaluating, or selecting more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs. This gap in existing regional transmission planning processes results in piecemeal, inefficient, and less cost-effective transmission planning that imposes real costs on customers, who pay Commission-jurisdictional transmission rates for less efficient or cost-effective transmission facilities and do not realize the benefits that would result from long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes that identify, evaluate, and select more efficient or cost-effective transmission

[182] NRECA Initial Comments at 14–16.

[183] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55 (quoting 16 U.S.C. 824e(a)).

[184] *Id.* at 55–59, 84 (affirming the Commission's authority to regulate transmission planning and cost allocation as practices affecting rates); *see also* Order No. 1000–A, 139 FERC ¶ 61,132 at P 577 (holding that ''requirements regarding transmission planning and cost allocation . . . are practices affecting rates.'').

[185] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 112, 116); *see also Emera Me.* v. *FERC,* 854 F.3d at 674.

[186] That is true even if regional transmission planning and cost allocation processes do not result in the development, siting, and construction of every regional transmission facility that transmission providers select to more efficiently or cost-effectively meet transmission needs. *See, e.g., Conn. Dep't of Pub. Util. Control* v. *FERC,* 569 F.3d 477, 485 (D.C. Cir. 2009) (holding that ''even if all [that] the I[nstalled] C[apacity] R[equirement] did was help to find the right [capacity] price,'' rather than result in the construction or procurement of any new capacity, ''it would still amount to a 'practice . . . affecting' rates.'' (citing 16 U.S.C. 824e(a) (omission in original))).

[187] *FERC* v. *Elec. Power Supply Ass'n,* 577 U.S. 260, 279 (2016) (*EPSA*).

[188] 16 U.S.C. 824e(a).

[189] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 54 (''The Commission's factual findings are conclusive if supported by substantial evidence.''). Courts have held that substantial evidence in this context does not necessarily require the Commission to provide *empirical* evidence for every proposition. Rather, FPA section 206 empowers the Commission to address a mere *threat* of unjust and unreasonable rates. *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64–65, 85.

[190] 16 U.S.C. 824e(a); *see also EPSA,* 577 U.S. at 277 (affirming the Commission ''has the authority—and indeed, the duty—to ensure that rules or practices 'affecting' wholesale rates are just and reasonable'').

solutions to Long-Term Transmission Needs.

88. We find that these deficiencies in the Commission's existing transmission planning and cost allocation requirements render those requirements unjust, unreasonable, and unduly discriminatory or preferential in violation of FPA section 206.

89. We also find that the Commission's existing transmission planning and cost allocation requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates. Given these findings, we are now requiring, pursuant to FPA section 206, that transmission providers engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs. We find that these reforms will facilitate a process by which transmission providers can better identify, evaluate, and select more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs, which will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

1. The Transmission Investment Landscape Today

90. As the Commission explained in the NOPR, a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity.[191] Due to continuing changes in the industry, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable,[192] affordable, and economically efficient fashion. Such investments support enhanced reliability, as larger, more integrated transmission systems result in a diversity of supply and demand conditions and a certain degree of redundancy that allows the system to better withstand failures during extreme events.[193] Proactive, forward-looking transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints, as well as to evaluate potential transmission solutions, well in advance of these issues affecting the transmission system,[194] which can facilitate the selection of more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.

91. In addition, transmission infrastructure can unlock the forces of competition, changing who can sell to whom, eliminating barriers to entry, and mitigating market power.[195] Increased competition, in turn, can provide a host of benefits for customers, including cost-savings from greater access to low-cost power and a wider range of resources.[196] Transmission infrastructure can also serve as a form of insurance against future uncertainties because a more robust, integrated transmission system has the potential to provide consumers with the benefits of competition and enhanced reliability even if supply and demand fundamentals change over time.[197]

92. With that overview, we again begin with the key facts on the ground.[198] Since the issuance of Order No. 1000, transmission spending has continued to increase nationwide. A study by US DOE found that ''annual investment [in transmission] first exceeded $5 billion per year in 2006 . . . and has increased consistently since that time. Annual investment [] doubled to more than $10 billion per year by 2010 and then [] doubled again by 2016. Annual investment has been between $18 billion and $22 billion annually since 2014.'' [199] A separate study, noted by the Commission in the NOPR, estimated that transmission developers in the United States invested $20 to $25 billion annually in transmission facilities from 2013 to 2020.[200] Unsurprisingly, in regions that saw a significant increase in transmission expenditures, transmission costs have also become an increasing

[191] NOPR, 179 FERC ¶ 61,028 at P 28 (citing 16 U.S.C. 824, 824d, 824e); *see also* US DOE ANOPR Initial Comments at 2 (stating that ''strengthening and expanding existing transmission infrastructure, particularly the development of regional and inter-regional transmission projects, is key to continued access to reliable, resilient, lower-cost, and clean electricity for all'').

[192] *See, e.g.,* MISO ANOPR Initial Comments at 40; Testimony of James B. Robb Before the U.S. Senate Energy and Natural Resources Committee, *Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events,* at 8–9 (Mar. 11, 2021), *https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11* (testifying that more transmission infrastructure is required to ensure the reliability and resilience of the bulk power system in light of changing conditions).

[193] ACORE ANOPR Initial Comments Ex. 4, Grid Strategies July 2021 Extreme Weather Report; Mark Chupka & Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience* (May 2018), *https://wiresgroup.com/wp-content/uploads/2020/06/2018-05-09-Brattle-Group-Recognizing-the-Role-of-Transmission-in-Electric-System-Resilience-.pdf*; NERC ANOPR Initial Comments at 17–18; US DOE ANOPR Initial Comments at 18.

[194] MISO's Multi-Value Project (MVP) regional transmission planning process, for example, eliminated the need for approximately $300 million in reliability transmission facilities, resolving reliability violations and mitigating system instability conditions, through a forward-looking approach. Midcontinent Independent System Operator, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio,* at 11, 33 (Sept. 2017) (MTEP2017 Review).

[195] Policy Integrity ANOPR Initial Comments at 13 n.40 (''A new transmission project can enhance competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load.'' (citing Mohamed Awad et al., *The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Applications to Path 26,* at 3 (2006)); PIOs ANOPR Initial Comments Ex. A, Johannes Pfeifenberger et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 48–49 (Oct. 2021) (Brattle-Grid Strategies Oct. 2021 Report), *https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf* (''Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade . . . .'' (quoting F.A. Wolak, World Bank, *Managing Unilateral Market Power in Electricity,* Policy Research Working Paper No. 3691, at 8 (2005))).

[196] *See, e.g.,* PJM Interconnection, L.L.C., *PJM Value Proposition,* at 1–2 (2019), *https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx* (PJM's planning of resource adequacy over a large region is estimated to result in savings of $1.2–1.8 billion.); Midcontinent Independent System Operator, *MISO Value Proposition* (2020), *https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/* (MISO estimated $517–572 million in savings from more efficient use of existing assets and $2.5–3.2 billion from reduced need for additional assets.); SPP Transmission Planning, Southwest Power Pool, *SPP's Value of Transmission: 2021 Report and Update* (Mar. 31, 2022) (SPP estimated $382.7 million in adjusted product costs savings in 2020 due to transmission investment.); *see also* ACEG Initial Comments at 3–4 (''The benefits generated by MISO's MVPs and SPP's Priority Projects exceeded the costs by 2.2 to 3.5 times and means that every dollar spent on transmission will enable access to generation that is $3 to $4 cheaper than would otherwise be available.'').

[197] US DOE, *National Electric Transmission Congestion Study,* at 11 (Sept. 2015), *https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf* (stating transmission expansion can strengthen and increase the flexibility of the overall network and ''create real options to use the transmission system in ways that were not originally envisioned''); Vikram S. Budhraja et al., *Improving Electricity Resource Planning Processes by Considering the Strategic Benefits of Transmission,* 22 ELEC. J. 54 (Mar. 2009) (high voltage transmission affords ''mitigation of risks as a form of insurance against extreme events'').

[198] NOPR, 179 FERC ¶ 61,028 at P 36.

[199] California Commission Reply Comments at 9 n.27 (quoting US DOE, *National Electric Transmission Congestion Study,* at 9–10 (Sept. 2020), *https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf*).

[200] NOPR, 179 FERC ¶ 61,028 at P 39 (citing Brattle-Grid Strategies Oct. 2021 Report at 2); Brattle Apr. 2019 Competition Report at 2–3 & fig.1.

share of customers' overall electricity bills, underscoring the importance of ensuring that transmission investments are efficient and cost-effective.[201]

93. Furthermore, the record demonstrates that transmission investment is likely to substantially increase in coming years. A number of studies project significant and sustained transmission spending through at least 2050. For example, one projection cited by the US DOJ and FTC states that ''high voltage transmission capacity must expand by 60 percent by 2030 at a capital cost of $330 billion, and must triple by 2050 at a capital cost of $2.2 trillion.'' [202] TAPS cites a separate study projecting $750 billion of new transmission investment between 2023 and 2050.[203] SoCal Edison ''estimates that grid investments of up to $75 billion, including transmission upgrades, will be required from 2030 to 2045 *in California alone* to integrate bulk renewable generation and storage and serve load growth associated with electrification.'' [204] And ISO–NE's recently-completed 2050 Transmission Study estimates that transmission investment in New England will range from $16 billion to $26 billion between 2024 and 2050, depending on the amount of load growth realized in the region.[205]

94. The growing need for new transmission infrastructure, particularly over a longer time horizon, is being driven by a number of factors. First, longer-term reliability needs are changing. The NOPR explained that transmission system operators are increasing their reliance on regional transmission facilities to ensure operational stability, particularly because of the growing frequency of extreme weather events and increasing share of variable resources entering the resource mix.[206] The comments submitted in response to the NOPR support that preliminary finding. The record shows that changing reliability needs are driving a significant shift in demands placed on the transmission system,[207] and that because extreme weather events are occurring with greater frequency, transmission is increasingly critical to ensuring system reliability.[208] For example, Winter Storm Uri demonstrated that transmission infrastructure can make critical contributions to system reliability during extreme weather events,[209] as well as how transmission constraints can prevent operational generation resources from being able to serve load during tight supply conditions.[210] Consistent with experience from Winter Storm Uri, US DOE's Lawrence Berkeley National Laboratory provides further evidence of the significant value of transmission during unanticipated events, with research suggesting that 50% of the value created by alleviating transmission system congestion occurs during only 5% of the hours during which the transmission system is used.[211] Thus, transmission investment is likely to be more critical, and produce more reliability benefits, for customers as extreme weather and other system contingencies become more frequent.[212] For some communities who can be more susceptible to the impacts of extreme weather, like communities of color and

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[201] Resale Iowa Initial Comments at 3 (''[T]ransmission costs have comprised an increasing percentage of [] total wholesale electric costs [for Resale Iowa's members]. Currently, transmission and ancillary services constitute approximately 43% of such costs, as compared to 18.1% in 2009.''); Industrial Customers Initial Comments at 5 (showing that transmission costs made up just 7% of the total PJM electricity bill in 2011 but 27% by 2020); Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* at 26–28 (Jan. 2021), *https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf* (ACEG Jan. 2021 Planning Report) (stating that the current approach to transmission planning ''results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning''); *see also* California Municipal Utilities Initial Comments at 10 (projecting that between 2022 and 2040, total high and low-voltage transmission access charges will nearly double and noting that ''[g]one are the days when transmission was a *de minimis* portion of the overall bill and increases had little impact on the end consumer''); Public Systems Initial Comments at 5 (noting that ''New England's Regional Network Service transmission rate has grown *nine-fold,* from $15.60 per kW-year (in 2003) to $140.98 per kW-year (in 2021)'').

[202] US DOJ and FTC Initial Comments at 3 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* Princeton Univ., 108 (Oct. 2021), *https://netzeroamerica.princeton.edu/the-report*).

[203] TAPS Initial Comments at 46 & n.133 (citing Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy,* at iii (2019), *https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf*)).

[204] SoCal Edison Initial Comments at 2 (citing Southern California Edison, *Pathway 2045: Update to the Clean Power and Electrification Pathway* (2019), *https://download.newsroom.edison.com/create_memory_file/?f_id=5dc0be0b2cfac24b300fe4ca&content_verified=True*) (emphasis added)).

[205] ISO–NE, *2050 Transmission Study,* at 55–56 (Feb. 12, 2024), *https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf*.

[206] NOPR, 179 FERC ¶ 61,028 at P 45.

[207] ACEG Initial Comments at 5 (noting that weather-related power outages cost Americans $25–70 billion annually (citing Grid Strategies July 2021 Extreme Weather Report at 1)); *id.* at 52 (explaining that ''[c]hanges to the transmission planning processes that would allow for certain transmission upgrades identified in the interconnection process to be addressed and ultimately constructed through the transmission planning process will only serve to increase the resiliency and reliability of the transmission system.''); ACEG Reply Comments at 5–6 (''[R]eliability requires long term transmission planning that incorporates known and knowable information about the future resource mix.''); NERC Initial Comments at 6 (''Transmission will be the key to support the resource transformation enabling delivery of energy from areas that have surplus energy to areas which are deficient. The frequency of such occurrences are increasing as extreme weather conditions resulting from climate change impact the fuel sources for variable energy resources. Regional transmission planning can ensure that sufficient amounts of transmission capacity will be needed to address these more frequent extreme weather conditions.'').

[208] *See* DC and Maryland Offices of People's Counsel Reply Comments at 2 (noting that new transmission development has benefits including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather); Indicated PJM TOs Initial Comments at 1 (explaining that maintaining a ''reliable and resilient'' transmission system requires holistic planning); NESCOE Initial Comments at 32–33 (''ISO–NE explains that energy-security risks in New England are well documented, highlighting the importance of conducting comprehensive energy security assessments covering a wide range of operating conditions, including low-probability, high-impact reliability risks (tail risks) related to extreme weather'' (internal quotations omitted)); NYISO Initial Comments at 16 (expressing a desire to engage in actionable scenario planning to plan for future reliability challenges that may arise due to extreme weather, including the loss of all generation connected to a pipeline or other fuel sources, loss of an entire transmission line, and impacts from weather events like hurricanes or wildfires).

[209] ACEG Initial Comments at 22 n.63 (During Winter Storm Uri, ''[a]n additional 1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion and kept power flowing to hundreds of thousands of Texans.'' (citing Grid Strategies July 2021 Extreme Weather Report at 1–3, 12)); Grid Strategies July 2021 Extreme Weather Report at 7–8 (''The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during [Winter Storm Uri]. . . . In contrast to the 13,000 MW MISO was importing during the peak of [the] event, ERCOT was only able to import about 800 MW of power throughout the event.''); NARUC Initial Comments at 67 n.192 (During Winter Storm Uri, SPP's '' 'relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them.' '' (quoting Southwest Power Pool, *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations,* at 9 (July 2021), *https://spp.org/documents/65037/comprehensive%20review%20of%20spp%27s%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf* (brackets omitted))).

[210] *See* Advanced Energy Buyers Initial Comments at 3.

[211] ACORE Initial Comments at 10–11 (citing LBNL Aug. 2022 Transmission Value Study at 33); US DOE Initial Comments at 5–6 & n.13.

[212] ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33; *see also* Clean Energy Associations Initial Comments at 5.

low-income communities, transmission investment has the potential to be even more critical.[213] Conversely, failure to adequately plan the transmission system to meet such changing reliability needs will forgo many of those potential benefits, jeopardize system reliability, and force customers to pay for transmission facilities that may not efficiently or cost-effectively address urgent reliability needs.

95. Second, demand is changing. After many years of flat or minimal load growth in regions across the country, demand, on both a national and a regional basis, is projected to significantly increase in the coming decades, and it will require an increasingly robust transmission system to reliably serve this load growth. As stated in the NOPR, changes in electric demand and associated load profiles are occurring as load-serving entities work to meet increasing needs due to electrification trends, as well as new large loads associated with evolving industrial and commercial needs, such as growth in data centers.[214] The comments submitted in this record demonstrate that, in regions across the country, customers are electrifying everything from household appliances to vehicles.[215] Comments also substantiate the fact that, in many regions, large loads associated with new and emerging industrial needs, like data centers, are driving rapid load growth.[216] Estimates quantifying the magnitude of this shift show that it is significant, with nationwide demand for electricity projected to increase by 5% to 15% (200 to 600 TWh) by 2030.[217] That trend is projected not just to continue but to accelerate, with nationwide demand for electricity projected to increase by 25% to 85% (1,100 to 3,700 TWh) by 2050.[218] Industrial customers in many regions are driving much of this increase; industry executives have reported that electrification initiatives, through which many of the Nation's largest companies plan to electrify their manufacturing processes, transportation, and heating operations, are well underway or soon to begin.[219] Importantly, the record shows that these increases in aggregate demand for electricity will have significant consequences for the transmission system. To serve more load, the capacity of the already-oversubscribed transmission system will need to increase.[220] Moreover, load growth driven primarily by electrification can create a load profile that has a higher load factor and that is thus more challenging to serve.[221]

96. Third, supply is changing. As the NOPR explained, Federal, state, and local policies are incentivizing various forms of generation resources and other technologies,[222] resulting in changes to the Nation's resource mix. The comments in this record show that these policies are widespread and now span

[213] *See, e.g.,* WE ACT Initial Comments at 1–2 & n.3 (citing Jeff Turrentine, NRDC, *A Roadmap for Frontline Communities* (Dec. 2019)); *see also* Grand Rapids NAACP Initial Comments at 8 n.20 (''[P]ower outages uniquely burden low-income communities of color 'given that they are unable to 'bounce back' as quickly from events that damage food and medicine supplies' '' (citing Shalanda Baker et al., *The Energy Justice Workbook 20* (2019), *https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf*)).

[214] NOPR, 179 FERC ¶ 61,028 at PP 45, 51. The continuation and, in some instances, acceleration of these trends identified in the ANOPR and NOPR counters certain commenters' concerns that changes in demand are inherently unpredictable or that existing regional transmission planning processes are adequately identifying and addressing transmission needs. *Compare infra* notes 21515–2188 and accompanying discussion, *with* Potomac Economics Initial Comments at 3–4 (arguing that Long-Term Regional Transmission Planning that requires speculating about future uncertainty is not advisable), *and* Industrial Customers Initial Comments at 10–11 (arguing that changes in demand are unpredictable).

[215] AEE Initial Comments at 1, 14 (noting that, as of 2022, ''[n]ine states have also taken steps directly to promote electrification of transportation and buildings. Individuals and governments are also adopting electric vehicles; for example, light-duty electric vehicle sales have increased from 10,092 vehicles in 2011 to 459,426 vehicles in 2021, over a 4400% increase.''); Renewable Northwest Initial Comments at 20 (explaining that heat pumps installed as part of building electrification could add large new weather-dependent loads, estimated at 20,000 to 40,000 MW of incremental peak capacity by 2050 across the Pacific Northwest); *see also* AMP Initial Comments at 4; ISO–NE, *Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results,* at 190–94 (Nov. 2023) (providing sensitivity that included 15% and 10% increases in peak load and average hourly loads, respectively, driven by heating and vehicle electrification); U.S. Energy Info. Admin. (EIA), *Incentives and Lower Costs Drive Electric Vehicle Adoption in Our Annual Energy Outlook,* (May 15, 2023) (noting that, per 2023 Annual Energy Outlook Projections, electric vehicles will account for between 13% and 29% of new light-duty vehicle sales in the United States, and between 11% and 26% of then on-road light duty vehicle stocks, by 2050).

[216] *See, e.g.,* Transmission Dependent Utilities Initial Comments at 4–5 (''For example, the PJM Interconnection, L.L.C. Transmission Expansion Advisory Committee recently posted that Dominion Energy Virginia will need over $603 million in transmission upgrades through 2025—just three years from now—to accommodate significant data center load growth in Northern Virginia.'' (citing PJM Transmission Advisory Committee, *Reliability Analysis Update,* at 3, 5 (Aug. 9, 2022))). These trends are continuing and even accelerating. *See* PJM Interconnection, L.L.C., *PJM Load Forecast Report,* at 1 (Jan. 2024), *https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx* (noting upward adjustments in 2024 load forecasts for certain zones to account for large, unanticipated load growth driven by data centers, a chip processing plant, and port electrification, among other factors); *id.* at 78 (projecting increase from 2,333 GWh in 2024 to 130,489 GWh in 2039 due to plug-in electric vehicles); *id.* at 30 (showing 1.0% higher load growth projection for 2024, 6% higher load growth projection for 2029, and 10.4% higher load growth projection for 2034, as compared to 2023 Load Forecast Report).

[217] National Grid Initial Comments at 8 (citing Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy* (Mar. 2019), *https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf*).

[218] *Id.; see also* John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over,* at 3 (Dec. 2023), *https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf* (''Over [2023], grid planners nearly doubled the 5-year load growth forecast. The nationwide forecast of electricity demand shot up from 2.6% to 4.7% growth over the next five years, as reflected in 2023 FERC [Form 714] filings. Grid planners forecast peak demand growth of 38 gigawatts (GW) through 2028.''); N. Amer. Elec. Reliability Corp., *2023 Long-Term Reliability Assessment,* at 33 (Dec. 2023), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf* (''Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022* [*Long-Term Reliability Assessment*], reversing a decades-long trend of falling or flat growth rates.'').

[219] Renewable Northwest Initial Comments at 20 (''A recent study done by Deloitte showed that 70 percent of executives in industrial manufacturing industries have plans for the electrification of industrial processes, and 50 percent of the executives who responded have goals to electrify vehicle fleets and space and water heating within their companies by 2030.'' (citing Stanley Porter et al., Deloitte, *Electrification in Industrials* (Aug. 2020), *https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/electrification-in-industrials.html*)).

[220] *See, e.g.,* National Grid Initial Comments at 6 (discussing preliminary findings of the ISO–NE 2050 Transmission Study, which show ''significant new transmission will be needed to reliably serve'' increased future loads assumed in the study (citing ISO–NE, *2050 Transmission Study* (2023), *https://www.iso-ne.com/static-assets/documents/2023/08/2050_study_ma_cetwg_2023_aug_final.pdf*)); Northwest and Intermountain Initial Comments at 5 n.12 (''For example, Bonneville Power Administration ('BPA') owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA's 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests.'' (citing BPA, *TSR Study and Expansion Process,* at 12 (Dec. 2021), *https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf.*)).

[221] MISO Initial Comments at 54 (''In addition, a return to load growth driven primarily by the electrification of transportation, space heating and water heating is creating a load profile that has a higher load factor and is more challenging to serve.''). Load factor refers to ''[t]he ratio of the average load to peak load during a specified time interval.'' U.S. Energy Info. Admin. (EIA), *Glossary* (last visited Mar. 2024), *https://www.eia.gov/tools/glossary/index.php?id=L.*

[222] NOPR, 179 FERC ¶ 61,028 at P 45.

many regions of the country. States and cities in the Northeast,[223] Mid-Atlantic,[224] Midwest,[225] West,[226] and Southeast [227] have adopted binding state laws requiring emissions reductions. Moreover, with the passage of the Inflation Reduction Act in 2022, Congress has enacted legislation that will further spur investment nationwide in renewable and non-emitting resources.[228]

97. Customers are also driving changes in the resource mix. In addition to increasing their aggregate demand for electricity, the NOPR explained that customers, including major corporations, in many regions are increasingly demanding that load be served by renewable or non-emitting resources.[229] Substantial evidence in the record supports the existence of this trend. Since 2014, for example, ''commercial and industrial customers have contracted for more than 52 GW of clean energy[.]'' [230] Furthermore, this trend is accelerating. In 2021 alone, energy customers voluntarily contracted for ''11.06 GW of clean energy.'' [231] The record demonstrates that, going forward, this shift is projected to continue, as forecasts show that Fortune 1000 companies will have up to 85 GW of new demand for renewable energy to meet their public sustainability commitments for 2030.[232] As also noted in the NOPR, utilities in many regions have made commitments to procure most or all of their electricity from renewable or non-emitting resources. For example, Exelon,[233] Dominion,[234] AEP,[235] and Southern [236] have all committed to achieve net-zero emissions by 2050, and each has set an interim goal to significantly reduce emissions by 2030. And, although utility commitments vary by utility and by region, the record shows that many utilities have announced some future emissions target.[237]

98. Furthermore, as noted in the NOPR,[238] the resource mix is also being affected by the changing economics of the resources that comprise the resource mix.[239]

99. Together, trends in economics, growing demand, and Federal, federally-recognized Tribal, state, and local policies are already resulting in significant changes in the resource mix. The record shows that as of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources.[240] Meanwhile, most of the capacity retirements are, and are projected to continue to be, coal resources.[241] Based

[223] National Grid Initial Comments at 6–7 (explaining how all six states in New England have renewable energy standards and how ISO–NE's 2050 Transmission Study demonstrates the demands that meeting those standards will place on New England's transmission system); *id.* at 7 (explaining how the Climate Leadership and Community Protection Act enacted in New York State requires 70% renewable generation by 2030, zero-emissions by 2040, and 85% economy-wide emissions reductions by 2050, and that transmission infrastructure will be critical in meeting those goals); NESCOE Initial Comments at 15 (''Achieving a decarbonized system is required by laws and mandates in Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.'').

[224] DC and MD Offices of People's Counsel Initial Comments at 18 (noting that ''both Maryland and the District have adopted ambitious jurisdiction-wide decarbonization policies applicable to the [electric distribution companies] regulated by their respective public service commissions.'').

[225] Illinois Commission Initial Comments at 5 (explaining that ''[i]n Illinois, the Climate and Equitable Jobs Act of 2021 . . . will affect the future resource mix and demand and lead to decarbonization and electrification. For example, [it] requires Illinois to completely transition to clean energy by 2050 and facilitates electrification through the promotion of electric vehicles.'').

[226] Renewable Northwest Initial Comments at 6 (explaining that, ''[c]urrently, 80 percent of NorthernGrid's load is subject to state clean energy laws, and by 2040 NorthernGrid will have 65 percent carbon-free energy.''); *id.* at 21 (explaining that Washington state's ''SB 5974 sets a goal of all vehicles sold in 2030 and beyond to be [electric vehicles], with that goal becoming a mandate in 2035[.]'').

[227] SREA Initial Comments at 25 (noting that North Carolina has adopted Renewable Energy and Energy Efficiency Portfolio Standards and enacted the North Carolina Carbon Plan).

[228] ACORE Initial Comments at 1–2 & n.2 (projecting that ''annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025–2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter.'' (citing REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022,* at 15 (2022), *https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-12.pdf*)); CARE Coalition Initial Comments at 17 (''Analysis suggests that the [Inflation Reduction Act] could more than triple clean energy production in the U.S. and lead to $600 billion in capital investment in clean energy infrastructure.'' (citing American Clean Power Ass'n, *It's a Big Deal for Job Growth and for a Clean Energy Future* (2022), *https://cleanpower.org/blog/its-a-big-deal-for-job-growth-and-for-a-clean-energy-future*)); Evergreen Action Initial Comments at 3–4 (discussing model showing that clean energy could comprise up to 81% of all U.S. generation as a result of increased incentives in the Inflation Reduction Act (citing John Larsen et al., Rhodium Group, *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act* (2022), *https://rhg.com/research/climate-clean-energy-inflation-reduction-act*)); NextEra Reply Comments at 5 (''The signing of the Inflation Reduction Act of 2022 . . . will only increase the demand for renewables in the coming years and accelerate corresponding demands on the transmission system.'').

[229] NOPR, 179 FERC ¶ 61,028 at P 45.

[230] Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers Alliance, *State of the Market 2022, https://cebuyers.org/state-of-the-market/*).

[231] Clean Energy Buyers Initial Comments at 7.

[232] Clean Energy Buyers Initial Comments at 7 n.13 (citing Clean Energy Buyers ANOPR Initial Comments at 21–22).

[233] Exelon Initial Comments at 2 (''Exelon has established ambitious targets and aims to be a leader in clean energy by continuing to reduce its own greenhouse gas emissions, including reducing operations-driven emissions 50 percent by 2030, relative to a 2015 baseline, and achieving net-zero operations by 2050.'' (citing Calvin Butler, Exelon Corporation, *We're on the Path to Clean* (Apr. 2021), *https://www.exeloncorp.com/grid/were-on-the-path-to-clean*)).

[234] Dominion Initial Comments at 3–4 (''Dominion Energy has committed to achieve net zero greenhouse gas emissions by 2050 and is investing in clean energy resources such as solar and wind.'').

[235] AEP Initial Comments at 4 n.12 (''AEP's goal is to reduce carbon emissions from directly owned generation by 80% by 2030 compared to 2000 levels and to achieve net-zero emissions by 2050.'' (citing AEP, *2022 Corporate Sustainability Report,* at 48 (2022), *https://www.aep.com/news/releases/read/8520/AEP-Releases-2022-Corporate-Sustainability-Report*)).

[236] Southern Initial Comments at 14 (''By 2019, Southern Companies had already achieved a 44% reduction in greenhouse gas emissions in pursuit of its goals of a 50% reduction by 2030 and net zero by 2050.'').

[237] *See, e.g.,* SREA Initial Comments at 41–42 (''Major utilities in the South, including Entergy, Dominion Energy, Duke Energy, NextEra, Tennessee Valley Authority, and Southern Company have all announced some version of a net zero carbon emission plan or commitment.'').

[238] NOPR, 179 FERC ¶ 61,028 at P 45 & n.72 (noting the average levelized cost of wind energy for commercial wind generation has decreased from $90 per MWh in 2009, to $35 per MWh in 2019 (citing Lawrence Berkeley National Laboratory, *Wind Energy Technology Date Update: 2020 Edition,* at 66 (Nov. 2020))); *id.* (noting that the average levelized power purchase agreement price for utility-scale solar generation has decreased from approximately $160 per MWh in 2009, to approximately $40 MWh in 2020 (citing Lawrence Berkeley National Laboratory, *Utility-Scale Solar Data Update: 2020 Edition,* at 32 (Nov. 2020))).

[239] *See* ACORE ANOPR Initial Comments at app. 1, p. 22 (ACEG Jan. 2021 Planning Report) (''Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.''); Dominion Initial Comments at 19 (noting how, during the 2010s, the fracking revolution and advanced technology for natural gas combined cycle generation lead to a shift away from coal and nuclear as ''baseload'' fuels and how, today, renewable energy resources are likewise undergoing a similar expansion); Evergreen Action Initial Comments at 3 (''Rapid innovation has made wind and solar power the lowest-cost resource in many areas of the country[.]'' (citing Univ. of Tex. at Austin Energy Inst., *Levelized Cost of Electricity in the United States by County* (2022), *http://calculators.energy.utexas.edu/lcoe_map/#/county/tech*); *see also* ACORE Reply Comments at 2 (''In all scenarios, building transmission that enables low-cost wind and other energy resources is often cheaper than the alternatives, such as use of higher-cost but local resources (and potentially additional storage).'' (citing Paul Denholm, et al., National Renewable Energy Laboratory, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035,* at 47–78 (Sept. 2022))).

[240] SREA Initial Comments at 1–2 (citing US Energy Info. Admin., *Today in Energy* (2021), *https://www.eia.gov/todayinenergy/detail.php?id=46416#*); *see also* AEE Initial Comments at 13 (noting that between 2011 and 2021, ''renewable generation nearly doubled, from 12.5% to more than 20%.'').

[241] AEE Initial Comments at 12–13 (''From 2011 to 2021, the proportion of U.S. electricity generated by coal plants dropped by almost half, from 42%

on the record, those trends are projected to continue, with over 1,300 GW of wind, solar, and storage resources in interconnection queues across the country as of 2021.[242] With the passage of the Inflation Reduction Act in 2022, many analysts are predicting that the shift toward renewable resources will accelerate.[243]

100. In light of these changing demands on the transmission system, the record also affirms what the Commission has long recognized: regional transmission planning that identifies more efficient or cost-effective transmission solutions to needs helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions.[244] Conversely, inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill for piecemeal, inefficient, and less cost-effective transmission solutions designed to meet short-term or small-scale transmission needs. Given the magnitude of transmission investment needed to meet customers' changing needs, it is essential that regional transmission planning be of sufficient scope and duration to help to ensure customers' money is well-spent on transmission infrastructure that can efficiently and cost-effectively meet those needs. Unfortunately, we conclude that this is not the case today and that existing regional transmission planning processes are inadequate to address the emerging Long-Term Transmission Needs that are expected to increasingly drive transmission investment in the coming decades.

101. Experience with the implementation of Order No. 1000 over the last decade has highlighted a critical gap in the Commission's existing transmission planning and cost allocation requirements. Notwithstanding the broad recognition that additional transmission infrastructure is needed to address the drivers noted above, regional transmission planning processes across the country have yielded only limited investments in regional transmission projects. As the Commission observed in the NOPR, investment in regional transmission facilities in some regions has declined compared to prior to Order No. 1000.[245] Moreover, across all the non-RTO/ISO regions, there has not yet been a single transmission facility selected since implementation of Order No. 1000.[246] The record also demonstrates that within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process do occur, much of that investment has been in transmission projects that only address immediate reliability needs.[247] We find that this evidence supports our conclusion that existing regional transmission planning processes are not of sufficient scope and duration to adequately or consistently identify transmission needs and associated opportunities to more comprehensively evaluate and select more efficient or cost-effective transmission solutions to those needs.

102. Indeed, in the limited instances in which transmission providers have followed processes that share many of the elements of the long-term, forward-looking, and more comprehensive regional transmission planning this

to under 22%'' (citing U.S. Energy Info. Admin., *U.S. Electricity Generation by Major Energy Source, 1950–2021* (2022), *https://www.eia.gov/energy explained//electricity/charts/generation-major-source.csv*)); California Commission Initial Comments at 65 (citing FERC, *State of the Markets 2020* (Mar. 2021); Renewable Northwest Initial Comments at 36 (using IRP data to show that utilities in NorthernGrid plan to retire 6,573 MW of coal, 1,476 MW of natural gas, 10 MW of wind, and 18 MW of solar, by 2040). FERC's State of the Markets 2020 report stated that 9.6 GW of coal capacity retired in 2020, which had a noticeable effect on coal's operating capacity share in most RTOs/ISOs. FERC, *State of the Markets 2020,* at 10, 12 (Mar. 2021). FERC's State of the Markets 2023 indicates that this trend is continuing, with coal generation declining 18.8% in 2023. FERC, *State of the Markets 2023,* at 4 (Mar. 2024). *See also* US DOE Initial Comments at App. B, pp. 8–9 (Rand et al., Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021* (Apr. 2021)).

[242] *See* US DOE Initial Comments app. B, at p. 26 (Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021* (Apr. 2022)) (noting that 676 GW of solar, 246 GW of wind, 213 GW of standalone battery capacity, and ~208 GW of hybrid battery capacity wait in interconnection queues across the U.S.). On the other hand, the number of coal and, relatedly, natural gas resources waiting to interconnect is limited. *See id.;* Colorado Consumer Advocates Initial Comments attach. 7, at p. 21 (''No new coal plants have been built for domestic utility electricity production since 2014[.]''); NESCOE Initial Comments at 15–16 (noting that new natural gas generation represented nearly 48% of the queue in 2017, but just 3% by March of 2022). Moreover, the updated version of the report to which US DOE cites indicates that the capacity of wind, solar, and storage in interconnection queues is still increasing. Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022* (Apr. 2023) (noting that 947 GW of solar, 300 GW of wind, 325 GW of standalone battery capacity, and ~358 GW of hybrid storage capacity, totaling over 1900 GW, wait in interconnection queues across the country).

[243] ACORE Initial Comments at 1–2 & n.2 (''[P]rojecting annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025–2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter.'' (quoting REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022,* at 15 (2022), *https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-12.pdf*)).

[244] Order No. 1000, 136 FERC ¶ 61,051 at P 55 (''[T]he narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities.''); *id.* P 68 (concluding that reforms that require transmission providers to engage in regional transmission planning and evaluate proposed alternatives that ''may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans . . . will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region.''); Order No. 890, 118 FERC ¶ 61,119 at P 524 (''[C]oordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.''); *see also* ACORE Initial Comments at 6 (demonstrating that effective regional transmission planning could significantly reduce total electric system costs compared to electric system costs that result from intrastate planning (citing Brattle-Grid Strategies Oct. 2021 Report at 12)); R Street Initial Comments at 8 (''[H]olistic transmission planning could improve economic efficiencies and save billions of dollars . . . . For example, MISO's 2022 long-range transmission plan results include $10 billion in transmission projects that support interconnection of 53,000 megawatts of new renewable generation and reduces other costs by $37–$68 billion. PJM similarly identified $3 billion in transmission upgrades that would save billions compared to the current practice of incremental upgrades through the interconnection process.'' (citing Johannes Pfeifenberger, Brattle Group, *Planning for Generation Interconnection,* at 5 (May 31, 2022), *https://www.esig.energy/event/special-topic-webinar-interconnection-study-criteria* (citation omitted))).

[245] NOPR, 179 FERC ¶ 61,028 at P 39 (citing ACEG Jan. 2021 Planning Report at 25 & fig. 8); *see also* ACORE ANOPR Initial Comments at 4 (''Despite the potential benefits, regional transmission investment has not increased and in some regions even has declined over the past decade.'') (citing ACEG Jan. 2021 Planning Report at 25)); State Agencies Initial Comments at 23 (''Regionally planned projects have [ ] declined in RTOs/ISOs . . . .'' (citing John C. Gravan and Rob Gramlich, NRRI Insights, *A New State-Federal Cooperation Agenda for Regional and Interregional Transmission,* at 2 (Sept. 2021), *https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685*)).

[246] NOPR, 179 FERC ¶ 61,028 at P 39 (citing LS Power ANOPR Initial Comments App. I at 18 & n.57); FERC, Staff Report, *2017 Transmission Metrics,* at 19 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf*); *see also* Western PIOs Initial Comments at 28 (''The Western Regional Planning Groups, with the exception of the CAISO, have not developed new projects from their current Order 1000 transmission planning process.'').

[247] Southwestern Power Group Initial Comments at 15; PIOs ANOPR Initial Comments at 93 & n.276; *see also* Ari Peskoe, *Is the Utility Syndicate Forever?,* 42 Energy L.J. 1, 56–57 (2021) (explaining, for example, that in ISO–NE, all but one of the transmission projects approved through the regional transmission planning process were immediate-need reliability projects).

order requires, customers have seen clear and quantifiable benefits. For example, as the Commission observed in the NOPR,[248] MISO's Multi-Value Project (MVP) transmission planning process proactively planned over a 20-year period for two key drivers of transmission needs: the impacts of changing state laws on the resource mix, and a large increase in the number of generator interconnection requests. To mitigate the uncertainties associated with such long-term projections of transmission needs, MISO relied on scenarios to consider a range of potential future conditions[249] and disclosed the assumptions and inputs underlying each scenario.[250] The MVP process then identified a portfolio of transmission projects that were projected to provide multiple kinds of reliability and economic benefits under all the alternate future scenarios studied.[251] This process resulted in MISO identifying, evaluating, and selecting transmission facilities that are estimated to generate $2.20 to $3.40 of benefit per dollar invested.[252]

103. The benefits to transmission customers of long-term, forward-looking, and more comprehensive regional transmission planning, which we discuss further below, are thus well-documented but realized all too infrequently under existing regional transmission planning processes. Relatedly, the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers,[253] which contributes to rates for transmission that are unjust and unreasonable.

104. The record demonstrates that significant expansion of the transmission system is occurring through one-off, piecemeal, interconnection-related network upgrades constructed in response to individual generator interconnection requests.[254] As the Commission observed in the NOPR, the evidence shows a sharp growth in both the total cost of interconnection-related network upgrades and in the cost of such upgrades relative to generation project costs.[255] The record indicates that the average cost of interconnection-related network upgrades is increasing over time as the transmission system is fully subscribed and demand for interconnection service outpaces transmission investment. As highlighted in the NOPR,[256] in 2020, MISO identified the need for nearly $2.5 billion in interconnection-related network upgrades to interconnect just 9.2 GW of generation in MISO South, and MISO expects to need over $3 billion in interconnection-related network upgrades for interconnection in MISO West.[257] Similarly, SPP identified the need for $4.6 billion in interconnection-related network upgrades to interconnect just 10.4 GW of new generation.[258]

105. Record evidence also shows that increases in interconnection costs are being driven, in many cases, by an expansion in the scope and complexity of interconnection-related network upgrades.[259] The Commission noted in the NOPR, for example, that interconnection-related network upgrade costs in MISO West went from approximately $300/kW in 2016 to nearly $1,000/kW in 2017.[260] The trend is evident in other parts of the country as well.[261] The costs of interconnection-related network upgrades are, in many cases, an ever-growing percentage of the total capital costs of new generation projects. According to one report, interconnection costs for new renewable resources were less than 10% of total generation project costs until a few years ago, but recently these costs have risen to as much as 50%–100% of the total generation project costs.[262] At the

[248] NOPR, 179 FERC ¶ 61,028 at PP 30–31 (citing Midcontinent Indep. Sys. Operator, *RGOS: Regional Generation Outlet Study,* at 2 (Nov. 2020)).

[249] *Id.* P 31 (citing MTEP2017 Review at 26–29).

[250] *Id.* (citing MTEP2017 Review at 16).

[251] *Id.* (citing MTEP2017 Review at 13).

[252] *Id.* P 30 (citing MTEP2017 Review at 4).

[253] ACORE Initial Comments at 4–5 (citing Brattle-Grid Strategies Oct. 2021 Report at 3); Clean Energy Associations Initial Comments at 5 (explaining that proactive, forward-looking transmission planning processes can reduces costs by nearly half as compared to incremental and reactive transmission planning processes); Ørsted Initial Comments at 5 (explaining that failure to proactively plan for offshore wind results in suboptimal transmission development, which can increase costs to ratepayers); Southeast PIOs Reply Comments at 2 (explaining that in the Southeast, ''snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an already overburdened populace.'').

[254] Pine Gate Initial Comments at 6, 8–10; PIOs Initial Comments at 9 (noting how most transmission planning is done through the generator interconnection process or local transmission planning).

[255] NOPR, 179 FERC ¶ 61,028 at P 37.

[256] *Id.* PP 37–38.

[257] ACORE ANOPR Initial Comments at 10 (citing ICF Sept. 2021 Interconnection Report at 2).

[258] *Id.* (citing ICF Sept. 2021 Interconnection Report at 3–4).

[259] *See, e.g.,* US DOE Initial Comments at 8 & n.20 (citing Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy,* at 13–16 (2021), *https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf*) (ACEG 2021 Interconnection Report); Will Gorman et al., *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy,* 135 Energy Policy 110994 (2019), *https://www.sciencedirect.com/science/article/pii/S0301421519305816*)); ACEG 2021 Interconnection Report at 13 (''[T]he costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than 'driveway' type facilities are need; larger roads and highways are required to alleviate the traffic . . . . [H]istorically, interconnecting wind projects have incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW.''); *id.* at 14 (''New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total $307/kW, with upgrade costs for individual interconnection requests as high as $677/kW.''); *id.* (''The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were $0.25/MWh and $1.72/MWh, respectively, or $19.07 kW and $61.83/kW, respectively . . . costs for newly proposed wind and solar projects, however, have now risen to $0.69/MWh and $3.66/MWh, respectively or $0.54/kW and $131.90/kW, respectively—more than a 100 percent increase.'').

[260] NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 14; NextEra ANOPR Initial Comments at 16 (citing Midcontinent Indep. Sys. Operator, *MISO 2020 Queue Outlook,* at 9 (2020), *https://cdn.misoenergy.org/MISO2020InterconnectionQueueOutlook445829.pdf*)).

[261] NOPR, 179 FERC ¶ 61,028 at P 38 (showing that, as of 2019, interconnection costs in PJM for constructed wind and solar projects were $19.07/kW and 61.83/kW, respectively, as compared to a greater than 100% increase to $54/kW and $131.90/kW, respectively, for projects newly proposed today) (citing *e.g.,* ACEG Jan. 2021 Interconnection Report at 14 & tbl.2)); NextEra ANOPR Initial Comments at 16–17 (stating that interconnection-related network upgrade cost estimates have nearly tripled for newly proposed wind projects, and more than doubled for solar projects in PJM); *see also* ACEG Jan. 2021 Interconnection Report at 16 (illustrating an increase in average interconnection-related network upgrade costs in NYISO from $67/kW in 2013 to $124/kW in 2019). *Compare* ACEG Jan. 2021 Interconnection Report at 15 (identifying interconnection-related network upgrade costs in 2013 in SPP as $89/kW), *with* ICF Sept. 2021 Interconnection Report at 2 (citing interconnection-related network upgrade costs of $448/kW for interconnection customers studied in SPP's system impact study published in April 2021)).

[262] NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 6); *id.* (stating that the rising interconnection costs of wind projects in MISO recently reached approximately 23% of the capital cost of the project) (citing ACEG Jan. 2021 Interconnection Report at 13)); *id.* (identifying the increase in interconnection-related network upgrade costs in SPP between 2013 and

same time, interconnection-related network upgrades have frequently transitioned from primarily small transmission facilities that serve the needs of a limited number of interconnection customers to the size and scope of what have traditionally been considered high voltage transmission facilities. For example, interconnection-related network upgrades have recently included demolishing and rebuilding multiple 500 kV transmission lines[263] and constructing long, double-circuit, 765 kV transmission lines,[264] all at significant cost to the interconnection customer initially—and ultimately to consumers.

106. Unlike regional transmission planning processes, however, the generator interconnection process is not designed to consider how to address transmission needs more efficiently or cost-effectively beyond the discrete interconnection request (or requests) being studied. Therefore, the generator interconnection process does not look at time horizons beyond the specific interconnection request(s) being studied, comprehensively assess any transmission needs beyond those created by the specific interconnection request(s), or achieve the economies of scale in transmission investment that long-term, forward-looking, and more comprehensive regional transmission planning processes can provide.[265]

107. We acknowledge that the Commission recently issued Order No. 2023, which requires transmission providers to reform their generator interconnection processes. But while Order No. 2023 aims to improve the efficient processing of interconnection queues, it does not attempt to remedy the discrete deficiency addressed in this final order: that existing regional transmission planning and cost allocation requirements do not require transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, Order No. 2023 seeks to ameliorate the fact that existing generator interconnection procedures and agreements were ''insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner[.]''[266] The interconnection queue backlogs and delays that were the Commission's focus in Order No. 2023 have arisen, in part, due to deficiencies in the existing transmission planning requirements. But the Commission found issues regarding the coordination between transmission planning and generator interconnection processes were beyond the scope of Order No. 2023 and, therefore, the Commission addressed only interconnection queue processes rather than also addressing transmission planning requirements.[267] Consequently, this final order addresses a root cause of interconnection backlogs and delays that Order No. 2023 did not—the failure of transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Accordingly, the need to reform this deficiency persists despite the Commission's reforms required by Order No. 2023.

108. While some commenters argue that transmission providers do not rely too heavily on the generator interconnection process to build transmission facilities,[268] we find that the record indicates otherwise. Specifically, as discussed above, the increase in both the total and average cost of interconnection demonstrates how much transmission investment is occurring on a one-off, incremental basis through generator interconnection processes.[269] The Commission has consistently and repeatedly found that interconnection-related network upgrades provide systemwide benefits,[270] a finding which courts have upheld.[271] In turn, we find that increasingly relying on interconnection customers' interconnection-related network upgrades to expand the capacity of the transmission system is inefficient and leads to less cost-effective transmission development than would result from long-term, forward-looking, and more comprehensive regional transmission planning, to the detriment of customers.

109. Separately, the record here also substantiates the NOPR's preliminary

2017 as representing an increase from around 8% to over 43% of the capital cost of wind generation (citing ACEG Jan. 2021 Interconnection Report. at 15)); NextEra ANOPR Initial Comments at 17 (similar)).

[263] NOPR, 179 FERC ¶ 61,028 at P 38 (describing interconnection-related network upgrades for a 120 MW solar plus storage project in southern Virginia to interconnect to PJM that cost as much as $12,086/kW (citing ACEG Jan. 2021 Interconnection Report at 15)).

[264] NOPR, 179 FERC ¶ 61,028 at P 38 (describing one interconnection-related network upgrade in SPP identified in the system impact study published in April 2021) (citing ACEG Jan. 2021 Interconnection Report at 15)); ICF Sept. 2021 Interconnection Report at 3 (same); NextEra ANOPR Initial Comments at 17 (same). In 2017, for example, SPP included a 165-mile, $1.34 billion double circuit 765 kV line in its Definitive Interconnection System Impact Study. *See* ACORE ANOPR Initial Comments Ex. 5, ICF Sept. 2021 Interconnection Report at 4.

[265] Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 15 (noting the reactive nature of generator interconnection processes); Exelon Initial Comments at 5 (explaining that the ''project-by-project approach of developing [interconnection-related] network upgrades'' using the generator interconnection processes will likely not result in efficient or cost-effective outcomes given the ongoing changes in the resource mix and demand); Pine Gate Initial Comments at 9 (explaining how piecemeal approaches to transmission planning, like the generator interconnection process, result in inefficiently small upgrades (citing ACEG Jan. 2021 Interconnection Report at 7)); PIOs Initial Comments at 10; SEIA Initial Comments at 2; Southeast PIOs Initial Comments at 37 (''The lack of any regular, formal proceeding to consider Alabama Power's comprehensive facility investment plan is troubling and ensures that both generation and transmission are considered on a project-by-project basis. This piecemeal approach to addressing transmission needs for individual generation resource decisions will cause sticker-shock every time and an institutional aversion to broader transmission investment, especially when transmission benefits are expressly ignored.'').

[266] Order No. 2023, 184 FERC ¶ 61,054 at P 36.

[267] Order No. 2023, 184 FERC ¶ 61,054 at PP 1741, 1743 (finding that, although ''several commenters argue in favor of greater coordination between generator interconnection and transmission planning or identify interconnection as a matter requiring interregional planning,'' those comments were beyond the scope of that rulemaking proceeding and noting that ''the Commission proposed reforms related to coordination between regional transmission planning and cost allocation and generator interconnection in'' the docket for this final order).

[268] Mississippi Commission Initial Comments at 9; North Carolina Commission and Staff Initial Comments at 5; Southern Initial Comments at 38–40.

[269] New Jersey Commission Initial Comments at 6–7 (noting that interconnecting 87.1 GW of capacity, which is needed to meet the PJM states' offshore wind and renewable portfolio standards goals, through the interconnection queue process alone is projected to cost $36 billion); US DOE Initial Comments at 8 (citing ACEG 2021 Interconnection Report at 13–16 (2021)).

[270] *See, e.g., Duke Energy Progress, LLC,* 181 FERC ¶ 61,229, at P 17 (2022) (rejecting Duke's claim that ''its customers reap no benefits from network upgrades that must be constructed on Duke's affected system'' because ''Duke's characterization disregards the existence of any benefits to its customers from the network upgrades''); *ISO New England Inc.,* 150 FERC ¶ 61,209, at P 386 (2015) (noting that there ''is a presumption that transmission system enhancements benefit all members of an integrated transmission system''); *Pac. Gas & Elec. Co.,* 106 FERC ¶ 61,144, at P 22 (2004) (explaining that ''the integrated grid is a single interconnected system serving and benefitting all transmission customers''); *Pub. Serv. Co. of Colo.,* 62 FERC ¶ 61,013, at 61,061 (1993) (''The Commission has reasoned that, even if a customer can be said to have caused the addition of a grid facility, the addition represents a *system* expansion used by and benefitting *all* users due to the integrated nature of the grid.'' (emphasis in original)).

[271] *See, e.g., Nat'l. Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d 1277, 1285 (D.C. Cir. 2007) (''We have endorsed the approach of 'assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.''); *W. Mass. Elec. Co.* v. *FERC,* 165 F.3d 922, 927 (D.C. Cir. 1999) (''When a system is integrated, any system enhancements are presumed to benefit the entire system.''); *City of Holyoke Gas & Elec. Dep't* v. *FERC,* 954 F.2d 740, 742–43 (D.C. Cir. 1992); *Me. Pub. Serv. Co.* v. *FERC,* 964 F.2d 5, 8–9 (D.C. Cir. 1992).

finding that the majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities.[272] Commenters explain that, in RTO/ISO regions, one half of the nearly $70 billion in aggregate transmission investments by Commission-jurisdictional transmission providers between 2013 and 2017 was approved outside of regional transmission planning processes.[273] This investment trend is continuing and accelerating. For example, in 2019, PJM approved 383 transmission-owner planned supplemental projects at a total cost of $3.75 billion, compared to only 80 regionally planned baseline projects at a total cost of $1.27 billion. Then, in 2020, PJM approved 236 supplemental projects at a total cost of $4.7 billion, compared to only 43 regionally planned baseline projects at a total cost of $413 million.[274] In MISO, baseline reliability projects and other local transmission projects have grown dramatically since 2010 and constituted 100% of approved transmission between 2018 and 2020 and 80% since 2010.[275] From 2019 to 2021, 63% of transmission investment by the three largest transmission owners in CAISO was in local transmission projects, and Pacific Gas and Electric forecasts that of the $13 billion it will spend on capital additions between 2022 and 2027, approximately 84% will be on local transmission projects.[276] In ISO–NE, spending on in-kind transmission replacements, which are not part of the regional transmission planning process, has been significant. Between 2016 and 2022, over $2.5 billion has been spent on in-kind replacement projects that have entered service and, as of 2022, an additional $3.122 billion of in-kind replacement projects had been proposed, planned, or were under construction.[277]

110. As with the growing reliance on the generator interconnection process to identify needed transmission system improvements, local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader regional transmission needs. Similarly, local transmission planning processes and in-kind replacement processes do not generally assess transmission needs based on a forward-looking multi-scenario assessment that more comprehensively accounts for the benefits of transmission infrastructure.[278] Therefore, transmission expansion in this incremental manner also misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission facilities to solve transmission needs, as well as to afford system-wide benefits that may not be achieved through piecemeal, one-off local transmission facilities. As stated above, the result is relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.

111. To be clear, our findings here are not intended to call into question the justness and reasonableness of either generator interconnection processes or local transmission planning processes, which each serve important roles in ensuring reliability and integrating new resources onto the transmission system.[279] Rather, the trends regarding use of these processes, as well as in-kind replacement processes, provide additional evidence to support our finding that existing regional transmission planning and cost allocation requirements are inadequate without reform. As discussed further in the next section, we conclude that the record regarding the current and projected transmission landscape—including the investment trends and changing drivers of that investment detailed above—highlights critical deficiencies in the Commission's current regional transmission planning and cost allocation requirements. In this final order, we address those deficiencies to help to ensure that customers receive the benefits of long-term, forward-looking, and more comprehensive regional transmission planning.

2. Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes

112. Based on the record, including comments submitted in response to the NOPR, as discussed below, we find that there is substantial evidence to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis. We find that the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We find that the status quo approach results in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

113. We therefore adopt, as modified by the discussion herein, the preliminary findings of the NOPR concerning the need for reform[280] and, pursuant to FPA section 206, conclude that revisions to the Commission's regional transmission planning and cost allocation requirements are necessary to ensure that Commission-jurisdictional rates, terms, and conditions are just, reasonable, and not unduly discriminatory or preferential. We find that, as stated in the NOPR,[281] absent the reforms instituted by this final order, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development.

[272] NOPR, 179 FERC ¶ 61,028 at PP 39–40.

[273] PIOs Initial Comments at 9.

[274] PIOs ANOPR Initial Comments at 31–44; *see also* Ohio Consumers Initial Comments at 5 (''Since 2017, in Ohio, less than 25% of the new investment in transmission has been associated with large regional transmission projects needed for reliability or economic efficiency.'').

[275] *See* PIOs Initial Comments at 10 n.31 (citing PIOs ANOPR Initial Comments at 49 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, 2)).

[276] *See* California Commission Initial Comments at 109–110.

[277] NESCOE Reply Comments at 6.

[278] PIOs ANOPR Initial Comments at 33–34 (citing ACEG Jan. 2021 Planning Report); ACEG Jan. 2021 Planning Report at 98–99.

[279] As discussed below, we separately find that specific existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential. *See infra* Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

[280] NOPR, 179 FERC ¶ 61,028 at PP 28–55.

[281] NOPR, 179 FERC ¶ 61,028 at P 33.

114. Based on the record, including the comments submitted in response to the NOPR, we find that there is substantial evidence to support the conclusion that deficiencies in the Commission's existing regional transmission planning and cost allocation requirements are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential. Specifically, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that these deficiencies render Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable because they result in transmission providers failing to identify Long-Term Transmission Needs, to evaluate and select more efficient or cost-effective transmission solutions to meet those transmission needs, and to allocate the costs of transmission facilities selected to meet those transmission needs in a manner that is at least roughly commensurate with benefits. Below, we address each deficiency in turn.

115. The first deficiency is that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to perform a sufficiently long-term assessment of transmission needs. This deficiency is present in multiple aspects of existing regional transmission planning processes, from the degree to which planning studies that identify transmission needs are sufficiently forward looking, to whether forward-looking assessments actually inform the evaluation, selection, and eventual cost allocation of regional transmission facilities. The record demonstrates that, under existing regional transmission planning and cost allocation processes, transmission providers typically identify and plan for transmission needs using a relatively near-term transmission planning horizon. Specifically, commenters have noted that most transmission planning regions do not plan beyond a 10-year transmission planning horizon. For example, commenters point out that ISO–NE, SERTP, and NorthernGrid plan using a 10-year transmission planning horizon,[282] while PJM notes that it plans using two different transmission planning horizons: a 5-year transmission planning horizon for what it refers to as its short-term transmission planning process and a 6-to-15-year transmission planning horizon for what it refers to as its intermediate-term transmission planning process.[283] While it is reasonable and necessary for regional transmission planning and cost allocation processes to include a near-term study of the transmission system, the absence of any consistent and sufficient longer-term assessment of transmission needs prevents transmission providers from identifying Long-Term Transmission Needs and considering regional transmission facilities that may be more efficient or cost-effective solutions to address those needs.[284]

116. This lack of a longer-term assessment of transmission needs is particularly problematic for a few reasons. First, shorter-term transmission planning fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide by allowing fewer or better designed transmission facilities to meet multiple transmission needs. For example, shorter-term transmission planning fails to provide the opportunity for transmission providers to identify, evaluate, and select regional transmission facilities that could address multiple transmission needs over various time horizons.[285] Moreover, shorter-term transmission planning fails to create opportunities to ''right size'' the replacement of aging transmission facilities to address multiple transmission needs over the longer term.[286] Second, constructing large (*e.g.,* high voltage or long distance) transmission facilities comes with long lead times: planning, permitting, and building regional transmission facilities can often take more than ten years.[287] As an example, the MVP initiative in the MISO region took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, and this period of 10 years does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval.[288] Finally, the useful life of

[282] Massachusetts Attorney General Initial Comments at 25 (''For example, the Commission's proposal to increase the required long-term transmission planning horizon to at least 20 years with 3-year reassessments would double the current long-term planning horizon for ISO–NE.''); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15); Southeast PIOs Initial Comments at 12 (''The 'independent reliability planning studies . . . start with the combined local transmission plans of participating utilities,' and the results comprise the ten-year regional transmission plan.'' (citation omitted)); Western PIOs Initial Comments at 8–9 (''NorthernGrid conducts transmission reliability plans on a two-year cycle, with each plan covering a 10-year time horizon.''); *see also* ITC Initial Comments at 9 (referring to the ''broad use of a 10-year planning horizon in the existing transmission planning processes of many major planning regions[.]'').

[283] PJM Initial Comments at 2 n.4.

[284] *See, e.g.,* MISO ANOPR Reply Comments at 5 (''[G]iven long-term needs of an evolving system, additional transmission is necessary to reliably serve customers now and into the future. These challenges require immediate action and further delay only increases the risk that system enhancements may not be in place in the timeframe needed.''); PIOs Initial Comments at 13 (''[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[.]''); US DOE ANOPR Initial Comments at 10 (stating that failure to plan transmission far enough ahead results in ''adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals.'').

[285] ACORE Initial Comments at 4 (''The narrowly focused current approaches [to transmission planning] do not identify opportunities to take advantage of the large economies of scale in transmission that come from 'up-sizing' reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals.'' (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)); PIOs ANOPR Initial Comments at 10–11; SEIA ANOPR Initial Comments at 14.

[286] ACORE Initial Comments at 4 (''[I]n-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.'' (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)). PJM's long-term assessment of the transmission system ostensibly uses a 15-year transmission planning horizon, for example, but does not account for changes to the generation mix beyond a 5-year period. *See* Concerned Scientists ANOPR Initial Comments at 10 & n.11 (''Generation additions are unchanged in the 15-year study period, as the input assumption has no additional information that would expand the set of generators included in the forecast.''); PSEG ANOPR Initial Comments at 11 (stating that ''in practice only new resources that are near the end of the interconnection queue process and have signed an Interconnection Service Agreement are considered in the RTEP base case.'').

[287] AEP Initial Comments at 11; Nevada Commission Initial Comments at 7 n.24 (noting that it took over seven years between the request to include a transmission line in an Integrated Resource Plan (IRP) and the in-service date, which did not include the lead time for developing the underlying application) PIOs Initial Comments at 14 (''[A] 20-year planning horizon was necessary given the time needed to site, permit, and construct transmission facilities or because states have longer-term public policy goals.''); Renewable Northwest Initial Comments at 5; SEIA Initial Comments at 6.

[288] AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio,* at 39 (2021).

transmission assets generally far exceeds even 20 years, so a 10-year transmission planning horizon is much too short to capture all of the benefits that regional transmission facilities can provide.[289]

117. Thus, relying solely on shorter-term transmission planning and studies fails to identify Long-Term Transmission Needs and, consequently, undervalues or entirely ignores the benefits of transmission investments to meet those needs. Moreover, the likelihood that near-term assessments will fail to identify Long-Term Transmission Needs and more efficient or cost-effective regional transmission facilities to meet those needs is higher during periods of rapid change, as the electric sector is now experiencing, during which the need for transmission infrastructure is expected to grow considerably.[290] We find that continuing with the status quo approach is resulting in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates.[291] As a result, among other things, customers are paying more than necessary or appropriate to meet their transmission needs, forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

118. The second deficiency is that the Commission's existing regional transmission planning and cost allocation requirements fail to require transmission providers to account adequately on a forward-looking basis for known determinants of Long-Term Transmission Needs. This deficiency is related to the first deficiency in the sense that both relate to the failure of the existing transmission planning requirements to require transmission providers to adequately plan for the foreseeable future. We find that, even following Order Nos. 890 and 1000, transmission providers have adopted widely divergent approaches to determining the factors that are relevant to identifying transmission needs within regional transmission planning.[292] Specifically, as commenters note, some existing regional transmission planning processes ignore trends in future generation and the impact of extreme weather.[293] Other commenters note that certain regional transmission planning processes ignore state laws or utility goals.[294] In addition to failing to adequately account for factors that shape the resource mix, commenters also assert that current regional transmission planning processes fail to account for factors that will shape future load, particularly new loads associated with electrification trends like, for example, electric vehicles[295] and data centers.[296] Although transmission providers in some transmission planning regions account for a wider range of the factors that drive Long-Term Transmission Needs when performing regional transmission planning studies than do others,[297] we find that transmission providers are not consistently or sufficiently accounting on a forward-looking basis for the known determinants of Long-Term Transmission Needs or accounting for such known determinants in a manner that ensures the identification and evaluation of more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

119. We recognize there is inherent uncertainty in forecasting,[298] and we

[289] SEIA Initial Comments at 6; US DOE Initial Comments at 33 (noting that transmission assets can have a useful life of at least 40 years).

[290] US DOE ANOPR Initial Comments at 10 (''Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers' expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution.''); Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report,* at 6 (July 28, 2022), *https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf* (''While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.'').

[291] *See, e.g., S.C. Pub. Serv. Auth.,* 762 F.3d at 56–59 (explaining that transmission planning processes are practices affecting rates pursuant to Section 206 of the FPA).

[292] ELCON Initial Comments at 3 (''While regional differences are important to consider, too much flexibility was provided to transmission providers in Order No. 1000 that . . . created a patchwork of planning processes further complicating planning and fostering additional balkanization of the grid[.]''); NOPR, 179 FERC ¶ 61,028 at P 50.

[293] GridLab Initial Comments at 4–5 (noting that SPP does not consider extreme weather events in its transmission plan); Grid Strategies July 2021 Extreme Weather Report at 5 (''[T]ransmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience.''); Renewable Northwest Initial Comments at 4, 8 (explaining that regional transmission planning in the Pacific Northwest does not model extreme weather events and generally does not reflect publicly available data such as utility IRPs or carbon reduction goals); *see also* Brattle-Grid Strategies Oct. 2021 Report at 36 (stating that production cost simulations that are typically used to estimate the economic benefit of regional transmission facilities assume no extreme weather events); SPP Market Monitor ANOPR Initial Comments at 3 & n.5 (describing that even SPP's more forward-looking scenario analysis of an emerging technology case in its Integrated Transmission Plan presently underestimates the actual growth of renewables so much that ''[w]ind capacity in service today (29.8 GW) already exceeds wind levels projected in both 2019 ITP futures that go out to 2029'').

[294] Acadia Center and CLF Initial Comments at 1 (''Order No. 1000 has failed to require public utility transmission providers to align their transmission planning and funding processes with state policies and objectives.'' (citing Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms,* at 4 (July 2022), *https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf*)); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15, which states that WestConnect, for example, does not include planning inputs that extend beyond generic, baseline projects nor ''knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets[.]''); SREA Initial Comments at 25 (stating that ''SERTP relies entirely on member utilities to self-nominate transmission study requests regarding public policy, meaning if utilities do not provide recommendations or requests, no SERTP study is completed. For instance, in 2021, SERTP stated, '[t]he SERTP did not receive *any input or proposals* for possible transmission needs driven by Public Policy Requirements for the 2021 planning cycle. Therefore, no possible transmission needs driven by Public Policy Requirements have been identified for further evaluation of potential transmission solutions in the 2021 SERTP planning cycle.' '' (emphasis in original)).

[295] *See, e.g.,* Clean Energy Buyers Initial Comments at 7–8; National Grid Initial Comments at 8; *see also* AEE ANOPR Initial Comments at 18 (stating that MISO projects electrification effects on load in its long-term regional transmission planning, but how other transmission providers account for electrification trends is not consistent or transparent).

[296] *See supra* note 2166; Rocky Mountain Institute Supplemental Comments at 1 (''Technology companies have begun requesting large interconnections for data centers that require increased electricity supply to power generative artificial intelligence.''); WIRES Supplemental Comments at attach. 1, p. 36 (Rob Gramlich, et al., *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)) (''Load growth is rising in much of the country, and it is happening in a way that is hard for any single entity to assess on their own. It varies by local area due to factors such as manufacturing plant and data center additions, plus expectations for end-use electrification and penetration of electric vehicles.'').

[297] *See, e.g.,* Renewable Northwest Initial Comments at 11, 14–15 (discussing how the MISO transmission planning process accounts for the future resource mix); Western PIOs Initial Comments at 23–24, 26–27 (explaining forward-looking aspects of the CAISO transmission planning process).

[298] We acknowledge NRG's comment that forecasting is inherently uncertain. NRG Initial Comments at 10–12. Sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation, however, is better than a lack of planning. The Commission may, by applying its expertise and experience to the record, determine what type and amount of transmission planning results in a just and

agree with Industrial Customers that current transmission planning is based on known and measurable factors.[299] However, we find, based on this record, that the universe of known and measurable factors that drive regional transmission needs extends beyond those that transmission providers currently consider as part of their regional transmission planning processes. Specifically, the record demonstrates that a multitude of factors like reliability needs driven by the impact of extreme weather, trends in future generation additions and retirements, load growth, Federal, federally-recognized Tribal, state, and local laws, and utility goals increasingly shape Long-Term Transmission Needs, are known and identifiable, and have reasonably predictable effects, especially in the aggregate.

120. As noted above, the record shows that the increasing frequency, duration, and intensity of extreme weather events are driving changes in Long-Term Transmission Needs to maintain system reliability.[300] Additionally, demand growth is a major driver of Long-Term Transmission Needs, and contrary to commenter assertions,[301] the record shows that evolving trends in load growth due to data centers, electrification, and industrial growth are driving Long-Term Transmission Needs.[302] Similarly, state laws, utility integrated resource plans and resource procurements, and other regulatory actions necessarily affect Long-Term Transmission Needs for Commission-jurisdictional transmission services.[303] Several commenters also support the broader consideration of anticipated generation retirements and interconnection requests in regional transmission planning processes because those factors shape the future resource mix and, therefore, Long-Term Transmission Needs.[304] Relatedly, many commenters highlight the impact of utility goals on the resource mix because such goals will impact transmission needs.[305] Yet, as described above, existing regional transmission planning processes frequently undervalue or entirely omit consideration of some or all of these factors. And while some existing regional transmission planning processes do a better job than others of incorporating different components of long-term, forward-looking, and more comprehensive regional transmission planning, the Commission's existing regional transmission planning requirements do not ensure that factors influencing future transmission will be sufficiently accounted for in that planning.

121. The failure to adequately consider such factors delays planning for the transmission system's changing operational needs until shortly before those transmission needs manifest. As a result, existing transmission planning processes are piecemeal and fail to take advantage of economies of scale in transmission investment or opportunities to address multiple transmission needs over multiple time horizons.[306] We find that engaging in regional transmission planning without adequate consideration of such factors leads to transmission investment that is not more efficient or cost-effective and renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.[307]

122. Third, the record demonstrates that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[308] For example, commenters note that many regional transmission planning processes focus too narrowly only on some benefits.[309] For instance,

reasonable rate. *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55 (''[I]n rate-related matters, the court's review of the Commission's determination is particularly deferential because such matters are either fairly technical or 'involve policy judgements that lie at the core of the regulatory mission.' '' (citing *Alcoa Inc.* v. *FERC,* 564 F.3d 1342, 1347 (D.C. Cir. 2009))). ''The court owes the Commission 'great deference' in this realm because '[t]he statutory requirement that rates be 'just and reasonable' is obviously incapable of precise judicial definition' and 'the Commission must have considerable latitude in developing a methodology responsive to its regulatory challenge[.]' '' *Id.* (citing *Morgan Stanley Cap. Grp.* v. *Pub. Util. Dist. No. 1,* 554 U.S. 527, 532 (2008); *Am. Pub. Gas Ass'n* v. *FPC,* 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

299 Industrial Customers Initial Comments at 11.

300 ACEG Initial Comments at 63 (''[T]he need to improve regional and interregional planning arises from the transformative changes occurring with respect to resource diversity, energy market efficiencies, technological changes, operational innovations and resiliency to withstand severe weather events. If transmission facilities are not constructed, these are all benefits that would otherwise be forfeited.''); NERC Initial Comments at 6; Evergreen Action Initial Comments at 2 (''[A]dditional transmission built under improved planning procedures would [ ] create large reliability benefits. With increasing extreme weather events due to climate change—including wildfires, winter storms, hurricanes, and more—additional transmission infrastructure and grid improvements are increasingly necessary for resilience purposes.''); WE ACT Initial Comments at 2 (''Requiring public utility transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events.'').

301 *See, e.g.,* Industrial Customers Initial Comments at 8–10 (arguing that demand is growing more slowly than in previous periods).

302 *See, e.g.,* Northwest and Intermountain Initial Comments at 5 n.12 (''For example, Bonneville Power Administration ('BPA') owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA's 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests.'' (citing BPA, *TSR Study and Expansion Process,* at 12 (Dec. 7, 2021), *https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf.*)); John Wilson and Zach Zimmerman, *The Era of Flat Demand is Over,* Grid Strategies, at 3, 6 (Dec. 2023), *https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf* (noting the 5-year load growth forecast has nearly doubled from 2.6% to 4.7% and ''transmission investments need to increase just to keep up with demand'').

303 *See, e.g.,* Acadia Center and CLF Initial Comments at 8 (''State laws are . . . essential considerations in planning transmission . . . as state laws drive substantial procurements of energy resources along with the concomitant need for additional transmission, as well as repurposed transmission and non-transmission grid solutions.''); AEE Initial Comments at 10 (noting that ''[a]s of September 2020, 38 states and the District of Columbia had adopted renewable portfolio standards, and 21 states (plus the District of Columbia and Puerto Rico)—representing more than half of the U.S. population—include a target of 100% renewable energy by 2050 or sooner. Many of these requirements have been enacted in statute and are binding on utilities and retail energy providers.'').

304 *See, e.g.,* Pattern Energy Initial Comments at 26 (''[T]he generation interconnection queues are indicative of the market and should also be a major source for generation assumptions in scenario planning (both near-term and long-term).''); SEIA Initial Comments at 9.

305 *See, e.g.,* Renewable Northwest Initial Comments at 6; SREA Initial Comments at 41–46 (''The major utility announcements of achieving net zero or some approximation affects the marketplace, especially in the [S]outheast.'').

306 PIOs Initial Comments at 10–11; Renewable Northwest Initial Comments at 8 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, iv).

307 *See, e.g.,* AEE Initial Comments at 10 (''Failing to take any of [the Commission-proposed factors] into consideration in developing long-term scenarios would risk under investment in needed regional transmission projects to meet transmission needs and potential[ly] result in unjust and unreasonable rates for transmission service.''); New Jersey Commission Initial Comments at 3–9 (arguing that ''[e]nsuring just and reasonable rates requires mandating long-term, multi-value, and portfolio based transmission planning.'').

308 *See* Order No. 1000, 136 FERC ¶ 61,051 at P 624 (declining to prescribe ''a particular definition of 'benefits' '').

309 Massachusetts Attorney General ANOPR Initial Comments at 22 (''New England's siloed approach to transmission planning inhibits identification of multi-value solutions.'' As part of ISO–NE's Boston 2028 Request for Proposals, ''[i]n focusing on cost-effectively solving reliability needs alone, ISO–NE rejected all but one of thirty-six proposals. While ISO–NE rejected some of these proposals for technical reasons, it eliminated several due to cost considerations alone.''); PIOs Initial Comments at 10 (''[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next

Continued

the Brattle-Grid Strategies Report concludes that ''most of [the Nation's recent transmission] 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.'' [310] As PIOs argue, the Commission's existing regional transmission planning and cost allocation requirements do not require that transmission providers assess ''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 . . . .'' [311] Other regional transmission planning processes fail entirely to consider cost savings associated with certain transmission facilities.[312]

123. Based on the record, we find that, as with the universe of known and measurable factors driving transmission needs, the benefits that regional transmission facilities provide extend beyond those benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes.[313] Failing to adequately identify and consider the benefits of such transmission facilities may lead to relatively inefficient or less cost-effective transmission development. In particular, the cost-benefit analyses that transmission providers often use as part of the evaluation process may fail to identify more efficient or cost-effective regional transmission facilities for selection because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities. Thus, the failure to adequately consider the benefits of regional transmission facilities results in, among other things, transmission customers forgoing benefits that may significantly outweigh their costs, which results in less efficient or cost-effective transmission investments and, in turn, contributes to Commission-jurisdictional rates that are unjust and unreasonable.

124. Given our findings above concerning the deficiencies in existing transmission planning requirements, and our conclusion that long-term, forward-looking, and more comprehensive regional transmission planning is needed, we also conclude that existing cost allocation requirements are deficient and must be modified to properly account for Long-Term Regional Transmission Planning. The Commission has long recognized the ''close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan,'' [314] and that cost allocation issues will often determine whether transmission providers and customers support the construction of new facilities.[315] Furthermore, experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states. As the Commission discussed in the NOPR and we continue to find in this final order, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[316]

125. Given the link between cost allocation and transmission planning, it is essential that cost allocation requirements for Long-Term Regional Transmission Facilities are appropriately tailored to the new Long-Term Regional Transmission Planning requirements of this order, particularly given the anticipated long-lead time for any regional transmission facilities developed and regionally cost allocated through this final order. Without proper alignment of the regional transmission planning and cost allocation requirements, it is less likely that transmission facilities selected in Long-Term Regional Transmission Planning will be developed, which would undermine the essential purpose of the regional transmission planning process, namely, the development of more efficient or cost-effective regional transmission facilities.

126. We find that the Commission's current cost allocation requirements, which were designed and established in the context of existing Order No. 1000 regional transmission planning processes, are insufficient to appropriately allocate costs associated with regional transmission facilities that are selected in accordance with the new Long-Term Regional Transmission Planning requirements that we establish in this final order. The Commission's existing Order No. 1000 cost allocation requirements contemplate the application of differing cost allocation methods to different types of transmission facilities. But we find that Long-Term Regional Transmission Planning, which accounts for multiple drivers of Long-Term Transmission Needs and results in Long-Term Regional Transmission Facilities that produce a broader set of benefits, warrants a different approach to cost allocation for such transmission facilities. Likewise, existing Order No. 1000 regional transmission planning processes do not mandate the consideration of specific benefits that we believe are appropriately considered as part of Long-Term Regional Transmission Planning. New information concerning these benefits uncovered through the transmission planning process may be relevant when allocating the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with their benefits.[317] Importantly, existing cost allocation requirements do not provide a dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods. We conclude such a role is particularly relevant to Long-Term Regional Transmission Planning, given: (1) the lengthy planning horizon over

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 . . . . [M]ultiple quantifiable benefits to transmission . . . are being ignored in the transmission planning process.'').

310 Brattle-Grid Strategies Oct. 2021 Report at 2.

311 PIOs Initial Comments at 10–11. The benefits cited by PIOs ''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.'' *Id.* at 11.

312 SREA Initial Comments at 24 (''SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the 'Economic Planning Studies' only evaluate the costs of potential upgrades to the system, but none of the benefits.'').

313 We disagree with Potomac Economics' arguments that the sole benefit of transmission is alleviating congestion and that congestion is primarily an economic issue, so investment in alleviating congestion should not exceed the benefit of doing so. *See* Potomac Economics Initial Comments at 3–4. As discussed *infra* in the Evaluation of the Benefits of Regional Transmission Facilities section alleviating congestion is just one of many potential benefits that transmission infrastructure provides, and transmission benefits beyond solving congestion are considered by transmission providers in regional transmission planning processes today.

314 Order No. 1000, 136 FERC ¶ 61,051 at P 496.

315 Order No. 890, 118 FERC ¶ 61,119 at P 557; *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 496.

316 NOPR, 179 FERC ¶ 61,028 at P 301; *infra* Regional Transmission Cost Allocation section.

317 *Ill. Commerce Comm'n* v. *FERC,* 576 F.3d 470, 477 (7th Cir. 2009) (*ICC* v. *FERC I*); Order No. 1000, 136 FERC ¶ 61,051 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).

which transmission projects might be identified, selected, and ultimately constructed; (2) the resultant increased uncertainty for Long-Term Regional Transmission Facilities; and (3) accordingly, the increased importance for state engagement regarding cost allocation to increase the likelihood such facilities obtain needed siting approvals from the states and are thus timely and cost-effectively developed. We therefore believe that it is both necessary and appropriate to establish specific cost allocation requirements that are tailored to the Long-Term Regional Transmission Planning reforms in this final order.

127. Based on the record, including comments submitted in response to the NOPR, we find that there is substantial evidence demonstrating that Long-Term Regional Transmission Planning and cost allocation to identify and plan for Long-Term Transmission Needs does not occur on a consistent and sufficient basis.[318] We find, in large part, that this is because of the deficiencies that we have identified above in the Commission's existing regional transmission planning and cost allocation requirements. In addition, we find that, in the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes, transmission providers are meeting many transmission needs by identifying transmission solutions and developing transmission facilities through other processes, *i.e.,* outside of the regional transmission planning and cost allocation processes,[319] or, as discussed above, in response to near-term reliability needs,[320] which may not identify the more-efficient or cost-effective solution.

128. To reiterate, the fact that transmission facilities are being identified and built outside of regional transmission planning processes and in response to near-term reliability needs is not inherently problematic. In many instances, as some commenters point out,[321] those processes may be well equipped to identify necessary and appropriate transmission solutions. Rather, the problem is that incremental and piecemeal expansion of the transmission system outside of regional transmission planning process misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to solve Long-Term Transmission Needs, as well as to afford system-wide benefits that may not be achieved through one-off transmission system upgrades.[322] To the extent that transmission providers may not be identifying and evaluating the more efficient or cost-effective transmission solutions needed to meet underlying transmission needs, including Long-Term Transmission Needs, over time, consumers will bear the costs of relatively inefficient or less cost-effective piecemeal transmission investment and expansion.[323]

129. We find that the concerns arising from the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes and the corresponding failure by transmission providers to identify and evaluate more efficient or cost-effective transmission solutions to Long-Term Transmission Needs are exacerbated by the fact that transmission needs in most transmission planning regions are drastically changing. Contrary to the claims of some commenters, we are not promulgating this order in an attempt to steer the resource mix and demand[324] based on a preference for certain resources over others.[325] Instead, the Commission is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's jurisdiction or control, including, but not limited to, the increasing frequency of extreme weather events, customer preferences, demand growth, economic and technological trends, and Federal, federally-recognized Tribal, state, and local policies.[326]

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[318] *See* New Jersey Commission Initial Comments at 8 (explaining that, outside of limited circumstances, PJM, Florida, ISO–NE, Southeastern Regional, South Carolina Regional, WestConnect, NorthernGrid, NYISO, SPP, and CAISO do not conduct multi-driver or portfolio transmission planning, which has required ratepayers to pay for tens of billions of dollars in unnecessary transmission projects); NextEra ANOPR Initial Comments at 71 (''While there are examples of longer-term planning currently being utilized by some regions, such as MISO's annual 15-year Futures assessment or SPP's 20-year Integrated Transmission Plan run every five years, there is no standard as to what time horizon long-term planning must study, nor how often this planning should be done. Further, no standards or guidelines exist as to what should be included in such long-term planning to ensure that customers are charged just and reasonable rates for the most efficient and cost-effective investments given the most comprehensive and up-to-date information available.''); Western PIOs Initial Comments at 4–28 (arguing that in the Western United States transmission planning outside of CAISO is not developed and is ineffective); Brattle-Grid Strategies Oct. 2021 Report at 13–15 & tbl. 2 (documenting inconsistent ''use of proactive, scenario-based, multi-value processes'' across various planning authorities, including NYISO, CAISO, MISO, PJM, ISO–NE, Florida, Southeast Regional, and South Carolina'').

[319] *See, e.g.,* LS Power Initial Comments at 46–50; PIOs Initial Comments at 9–10 (explaining that about half of the approximately $70 billion in aggregate transmission investment by Commission-jurisdictional transmission owners in RTO/ISO regions was approved outside of regional transmission planning processes).

[320] *Supra* note 309.

[321] *E.g.,* Duke Initial Comments at 7.

[322] *See, e.g.,* ACORE Initial Comments at 8 ((''For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective.'') (quoting Brattle-Grid Strategies Oct. 2021 Report at 30)); Clean Energy States Initial Comments at 2 (''[T]he one-plant-at-a-time approach to transmission upgrades results in a patchwork approach that drives up costs and misses opportunities for improvements to the system as a whole.''); Exelon Initial Comments at 5.

[323] Michigan State Entities Initial Comments at 1–2 (explaining concerns that the lack of long-term transmission planning has led to significantly higher residential rates and how the problem will worsen if transmission investment does not reflect changes in the resource mix and demand); New Jersey Commission Initial Comments at 6–7 (noting PJM analysis showing transmission upgrades to interconnect 87.1 GW of a variety of resources, including offshore wind, would cost $3.2 billion if done through holistic transmission planning whereas connecting only 15.4 GW of offshore wind would cost $6.4 billion if done through the interconnection queue process, and estimating that the interconnection of 87.1 GW through the interconnection queue would increase the cost to consumers by over $30 billion compared to holistic transmission planning); PIOs Initial Comments at 8 (noting how deficiencies in the Commission's regional transmission planning processes have ''led to billions of dollars in excessive costs for consumers.'' (citing Brattle-Grid Strategies Oct. 2021 Report at 1–13 (Section 1)).

[324] Consumer Organizations Initial Comments at 1–2; ELCON Initial Comments at 9; SERTP Sponsors Initial Comments at 16–20. *But see* SEIA Reply Comments at 2–3 (''The NOPR does make 'repeated references' to the changing resource mix. But that is not because the NOPR will 'promote a transition to a more renewables-heavy electric system.' The NOPR makes these references because the resource mix is, in fact, changing. The question before the Commission is not whether to promote or impede that change, but how to address the needs of the grid as a result of that inevitable change.'' (internal quotations omitted)); New Jersey Commission Reply Comments at 2 (''The Commission is . . . trying to ensure the electricity system can reliably and efficiently achieve the generation mix that state policymakers and voluntary consumers—not the Commission—have chosen. Ensuring that these customers are served at the lowest possible cost while maintaining reliability is entirely consistent with and indeed required in order to meet the dictates of the FPA. In other words, the Commission is acting to ensure transmission planning processes account for current realities and meet evolving consumer needs at a total cost that is just and reasonable.'' (internal citations omitted)).

[325] *See, e.g.,* Ohio Commission Federal Advocate Initial Comments at 4–6 (arguing that the Commission's purpose in issuing the NOPR was to promote an aspirational renewable future and achieve narrow environmental objectives); Undersigned States Reply Comments at 7 (arguing that the Commission is forcing ratepayers to subsidize forms of energy by socializing the cost of a transmission build out).

[326] *See* New Jersey Commission Initial Comments at 3 (''The Commission is not proposing to unduly favor, mandate, or subsidize forms of generation but is rather seeking to ensure that the bulk electricity

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130. In response to commenters, we acknowledge that integrated resource planning processes, where they exist, shape the resource mix and can often include forms of proactive transmission planning. As stated in Order No. 1000, we reiterate that ''the regional transmission planning process is not the vehicle by which integrated resource planning is conducted.'' [327] Indeed, this final order does not aim to affect—either facilitate or hinder—any changes or decisions that occur outside of the Commission's jurisdiction. Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential. To this end, this final order is focused on ensuring that regional transmission planning processes are adequately *accounting for* the changes occurring outside of the Commission's jurisdiction, including the resource decisions that are the exclusive jurisdiction of states.[328] Additionally, to the extent that integrated resource planning processes include forms of transmission planning, such planning can be complementary to Commission-jurisdictional regional transmission planning processes but cannot take the place of such processes. This is not to diminish the importance of integrated resource planning processes, which serve a critical role in shaping the generation mix and transmission infrastructure. In recognition of this role, this final order requires transmission providers to consider integrated resource planning as a factor when conducting Long-Term Regional Transmission Planning. But, as discussed below, we conclude that integrated resource planning is appropriately considered as *one of several* categories of factors used to develop Long-Term Scenarios and identify Long-Term Transmission Needs.

131. In response to commenters that argue regional transmission facilities may not address local transmission needs such that a local transmission facility would still be needed,[329] we acknowledge that regional transmission facilities are not necessarily always a more efficient or cost-effective solution to address local transmission needs, and nothing in this final order requires transmission providers to rely on regional transmission facilities to address exclusively local transmission needs. Instead, this final order identifies deficiencies in existing Commission-jurisdictional regional transmission planning processes that lead transmission providers to fail to identify Long-Term Transmission Needs and fail to identify, evaluate, or select more efficient or cost-effective transmission solutions to meet those transmission needs. As a result of these deficiencies, transmission providers may undertake relatively inefficient investments in transmission infrastructure by missing opportunities to identify regional transmission facilities that bring economies of scale or address multiple transmission needs over different time horizons, including local transmission needs.

132. We disagree with arguments that the Commission cannot promulgate this final order because we rely on general findings, rather than individualized analyses of each, specific transmission planning region.[330] Relevant precedent, including regarding the Commission's comparable action in Order No. 1000, is clear that the Commission has discretion as to the procedural means through which it will apply its substantive expertise, and we need not make findings that are region specific in every case; rather, we are empowered to ''rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution,'' [331] and we do so here. The fact that individual transmission planning regions may have different forms of transmission planning processes, and may experience varying levels of transmission investment, would be ''as unastonishing as it is irrelevant.'' [332] Moreover, although transmission planning practices vary considerably between transmission planning regions and some regions may engage in transmission planning that shares many of the elements of the more long-term, forward-looking, comprehensive regional transmission planning required in this order, the record demonstrates that this final order identifies deficiencies that reach well beyond ''isolated pockets[.]'' [333] Rather, the record demonstrates that these deficiencies pervade large swaths of the country, which include RTO/ISO and non-RTO/ISO transmission planning regions.[334] Accordingly, this final order's remedy does not present an ''extreme 'disproportion of remedy to ailment[.]' '' [335] The Commission may reasonably rely on a rulemaking procedure to address the industry-wide changes to the transmission landscape, notwithstanding regional variation among regional transmission planning processes. As the Commission stated in Order No. 1000, ''[i]t is well established that the choice between rulemaking and case-by-case adjudication 'lies primarily in the informed discretion of the administrative agency.' '' [336] The Commission also stated that ''[i]t is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry wide problems facing us.'' [337] Moreover, we agree with ACEG that pursuing region-specific solutions will lead to ''siloed and disjunctive transmission planning policies [that] will not solve the problems facing the nation's electric grid.'' [338]

133. Furthermore, although not every transmission planning region is experiencing these changes in equal measure, the record shows that significant changes are well underway nationwide, and that failing to adequately account for Long-Term Transmission Needs poses a risk to just and reasonable rates throughout the country.[339] In fact, the record raises a wide range of concerns, and the Commission need not, and should not, wait for systemic problems to undermine regional transmission

system maintains reliability and satisfies evolving consumer demand . . .'').

[327] Order No. 1000, 136 FERC ¶ 61,051 at P 154.

[328] *See PJM Power Providers Grp.* v. *FERC,* 88 F.4th 250, 275 (3d Cir. 2023) (holding that the Commission is ''unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus . . . .''); *see also Elec. Power Supply Ass'n* v. *Star,* 904 F.3d 518, 524 (7th Cir. 2018) (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois ''as givens and set out to make the best of the situation [these systems] produce'').

[329] *See, e.g.,* Duke Initial Comments at 9 (arguing that there are instances in which larger regional transmission projects may not resolve localized transmission needs).

[330] *See, e.g.,* Louisiana Commission Reply Comments at 5–6; NRECA Initial Comments at 14–16.

[331] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67 (quoting *Interstate Nat. Gas* v. *FERC,* 285 F.3d 18, 37 (D.C. Cir. 2002)).

[332] *Id.* (quoting *Wis. Gas* v. *FERC,* 770 F.2d 1144, 1157 (D.C. Cir. 1985)).

[333] *Id.*

[334] *See, e.g., supra* notes 283 and 284 (explaining that ISO–NE, SERTP, Northern Grid, and PJM undergo transmission planning using time horizons shorter than 20 years).

[335] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67.

[336] Order No. 1000, 136 FERC ¶ 61,051 at P 60.

[337] *Id.*

[338] ACEG Reply Comments at 17.

[339] AEE Reply Comments at 3–4.

planning in every region before it acts.[340] The record in this proceeding confirms that significant investments in new transmission facilities are expected to occur, with substantial impacts on the Commission-jurisdictional rates that customers pay.[341] It is therefore critical, and it is the Commission's responsibility, to act now to address deficiencies in its regional transmission planning and cost allocation requirements to ensure that more efficient or cost-effective transmission investments are made as the industry addresses the changing landscape.[342]

3. Benefits of Long-Term Regional Transmission Planning and Cost Allocation To Identify and Plan for Long-Term Transmission Needs

134. Upon consideration of the record, we find that the requirements set forth in this final order will address deficiencies in the existing regional transmission planning and cost allocation requirements and will promote enhanced reliability and more efficient or cost-effective transmission solutions, which will help to ensure just and reasonable Commission-jurisdictional rates.

135. The record demonstrates that long-term, forward-looking, and more comprehensive regional transmission planning that identifies Long-Term Transmission Needs will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to those needs. For example, like the Commission in the NOPR,[343] commenters cite to the success of MISO's Long-Range Transmission Plan in delivering more efficient or cost-effective transmission solutions. By addressing public policy, economic, and reliability transmission planning needs simultaneously through its MVP category, MISO '' 'eliminate[d] the need for $300 million in future baseline reliability upgrades,' and provided production cost savings that *exceeded the entire cost of the portfolio by $10 billion.*'' [344] Brattle Group and Grid Strategies also found that ''building out piecemeal network upgrades through the interconnection queue process to integrate the same amount of generation would have cost over 80% more than the cost of the MVP portfolio.'' [345] Similarly, the New Jersey Commission asserts that, by planning transmission facilities to address a specific set of known and identified transmission needs through a holistic portfolio, rather than piecemeal through the generator interconnection process, PJM could save customers more than $30 billion.[346]

136. We note that the cost-saving results that MISO experienced were the direct product of more comprehensive, longer-term regional transmission planning. By expanding the transmission planning horizon and considering factors affecting Long-Term Transmission Needs, as well as considering a broader list of benefits, transmission providers will be able to identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs.[347] Such Long-Term Regional Transmission Planning will: (1) reduce reliance on transmission solutions that are relatively inefficient or less cost-effective because they address only short-term transmission needs; (2) unlock the benefits of economies of scale in transmission investment; [348] (3) enable opportunities to ''right size'' replacement transmission facilities; [349] (4) facilitate the selection of regional transmission facilities that could address multiple transmission needs over different time horizons; and (5) provide states, utilities, customers, and other stakeholders with greater insight and transparency into the costs and benefits of particular transmission solutions to address Long-Term Transmission Needs. We conclude that these regional transmission planning and cost allocation reforms will benefit customers by leading to more efficient or cost-effective transmission investment, thereby helping to ensure just and reasonable rates.[350]

137. In addition to potentially enhancing the efficiency and cost-effectiveness of transmission investment, we find that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes will enhance reliability. In the NOPR, the Commission found that a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity. The record supports this conclusion. Many commenters agree that, especially in light of continuing changes in both supply and demand, ongoing investment in regional transmission facilities is necessary to ensure that the transmission system continues to serve load in a reliable manner at reasonable cost.[351] Commenters also agree that regional transmission investments support enhanced reliability because larger, more integrated transmission systems are better equipped to accommodate a diversity of supply and demand conditions and provide redundancy that allow the system to better withstand unpredictable and extreme weather events, which are

[340] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 50.

[341] *See supra* P 93.

[342] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 46.

[343] *See, e.g.,* NOPR, 179 FERC ¶ 61,028 at PP 31–32.

[344] New Jersey Commission Initial Comments at 4 (citing MTEP2017 Review at 6, 8) (emphasis in original).

[345] *Id.* at 4–5 (citing Brattle-Grid Strategies Oct. 2021 Report at 7 & nn.13–14); *see id.* at 5 n.9 (noting that the cost of the MVP portfolio divided by the amount of wind capacity it interconnected came to $412 per kilowatt, while interconnection-related network upgrades for new generation in MISO planned through the interconnection queue cost $756 per kilowatt).

[346] *Id.* at 6–7 (citing Brattle-Grid Strategies Oct. 2021 Report at 7); *id.* (explaining that the onshore network upgrades required to interconnect 87.1 GW of resources meeting all of PJM states' current offshore wind goals and total renewable portfolio standards through ''piecemeal interconnection queue projects would cost nearly $36 billion in total—*more than eleven times* the $3.2 billion cost of the integrated portfolio approach,'' or ''[p]ut another way, proactive, portfolio-based planning in PJM could ultimately save ratepayers over $30 billion compared to the status quo.'').

[347] PIOs Initial Comments at 35.

[348] *Id.* at 10 (''[T]he 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.'').

[349] ACEG Initial Comments at 53–56; Clean Energy Associations Initial Comments at 25–27; SEIA Initial Comments at 25–26.

[350] *See, e.g.,* Exelon Initial Comments at 5 (''The project-by-project approach of developing [interconnection-related] network upgrades in response to generator interconnection requests does not take into account broader, longer-term planning needs and furthermore raises questions about whether it will lead to efficient and cost-effective outcomes as the resource mix rapidly evolves.''); PIOs Initial Comments at 8 (''[O]verwhelming evidence indicates that transmission owners are largely able to evade the requirements of Order No. 1000 and . . . have primarily invested in local projects. This has led to . . . billions of dollars in excessive costs for consumers.'' (citing Brattle-Grid Strategies Oct. 2021 Report at Section 1)); Southeast PIOs Reply Comments at 2 (''All the while, snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an already overburdened populace.'').

[351] ACORE ANOPR Initial Comments at 21–22 (explaining how additional transmission investments can alleviate billions of dollars in costs caused by extreme weather); EEI Initial Comments at 4 (''Transmission plays and will continue to play a vital role in enabling the energy transition and in ensuring a reliable and resilient energy grid. A robust transmission system will not only enable electric utilities to integrate more renewable energy resources and deliver more clean energy to customers but will also enhance the reliability and resiliency of the grid and enable the deployment of new technologies.'' (citing EEI, *Planning and Developing Electric Transmission Projects: The Path to the Grid of the Future* (2022)); NERC Initial Comments at 6 (explaining that transmission will be key to managing a reliable transformation in the resource mix).

occurring with increased frequency and severity.[352]

138. Moreover, commenters provide examples of how long-term, forward-looking, and more comprehensive regional transmission planning can better identify reliability needs and resolve these needs with more efficient or cost-effective transmission solutions.[353] For example, as noted above, MISO's MVP Portfolio 4 eliminated the need for $300 million in future baseline reliability upgrades.[354] By comparison, the Reliability Must-Run Agreement for Indian River Unit 4, a 410 MW coal-fired generation unit, highlights the costs of inadequate regional transmission planning. As NARUC explains, the Indian River Unit 4 was scheduled to retire, but PJM found that retirement would cause reliability issues and would necessitate upgrades to transmission facilities that, due to their age, were already due to be upgraded, and that the Reliability Must-Run Agreement was needed because those upgrades would take five years to complete.[355] A long-term, forward-looking, and more comprehensive regional transmission planning process may have obviated the need for the Reliability Must-Run Agreement, the individual transmission facility upgrades, or both.

4. Conclusion

139. In consideration of the record provided in this proceeding, as well as the related conclusions stated above, we find that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential because they fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis. Specifically, as discussed, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that reforms to those requirements are thus necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential. The failure to plan on a sufficiently long-term, forward-looking, and comprehensive basis results in the potential for relatively inefficient or less cost-effective transmission development for which customers must pay. The requirements set forth in this final order will help to ensure that transmission providers plan to address Long-Term Transmission Needs, in turn helping to ensure more efficient or cost-effective transmission development and thus just and reasonable Commission-jurisdictional rates.

III. Long-Term Regional Transmission Planning

A. Requirement To Participate in Long-Term Regional Transmission Planning

1. NOPR Proposal

140. In the NOPR, the Commission proposed to require each transmission provider to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning,[356] meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify transmission needs driven by changes in the resource mix and demand and to identify and evaluate transmission facilities for potential selection as the more efficient or cost-effective transmission facilities to meet such needs.[357]

141. The Commission proposed that transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.[358]

142. The Commission proposed that transmission providers that comply with the Long-Term Regional Transmission Planning requirements will comply with the requirement in Order No. 1000 that they participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.[359] The Commission further proposed to allow transmission providers to propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes they use to consider transmission needs driven by Public Policy Requirements.[360] The Commission stated, however, that such continued use of existing regional transmission planning and cost allocation processes would not supplant transmission providers' obligations to comply with the Long-Term Regional Transmission Planning requirements established in any final order in this proceeding. Moreover, the Commission proposed that transmission providers seeking to retain existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements would have to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning proposed in the NOPR by demonstrating that continued use of such processes is consistent with or superior to any final order issued in this proceeding.[361]

143. The Commission preliminarily found that transmission providers could propose a regional transmission planning process that plans for reliability needs, economic needs, transmission needs driven by Public Policy Requirements, and transmission needs driven by changes in the resource mix and demand simultaneously through a combined approach. The Commission stated that transmission providers proposing to address all such transmission needs in a single regional transmission planning process would bear the burden of demonstrating continued compliance with Order No.

[352] NERC Initial Comments at 6 (explaining that regional transmission planning is necessary to ensure sufficient transmission capacity to move energy from areas with a surplus to areas that are deficient).

[353] ITC Initial Comments at 44 (''While local transmission planning continues to serve a critically necessary, valuable function in maintaining the reliability and efficiency of transmission systems, it is nonetheless clear that holistic, long range transmission planning is far more capable of identifying optimal transmission solutions that serve the most needs and deliver the most benefits.''); MISO Initial Comments at 88 (explaining that in its Tranche 1 Long Range Transmission Plan, MISO recognizes Avoided Transmission Investment benefits provided by Long Range Transmission Plan facilities in addressing both avoided reliability projects and avoided age and condition replacement projects with the results being avoided costs in local transmission that would have otherwise been incurred to replace existing facilities).

[354] New Jersey Commission Initial Comments at 4.

[355] NARUC Initial Comments at 14–15.

[356] The two features of Long-Term Regional Transmission Planning that the Commission included in the proposed reforms were the development of scenarios with a 20-year transmission planning horizon to be reassessed and revised every three years, with each such re-assessment providing the basis for identification and evaluation of transmission facilities for potential selection. NOPR, 179 FERC ¶ 61,028 at P 68 n.128.

[357] *See id.* PP 54, 64, 68.

[358] *Id.* P 72.

[359] *Id.* P 73.

[360] *Id.* P 74.

[361] *Id.*

1000 in addition to compliance with the requirements of any final order in this proceeding.[362]

144. Finally, the Commission proposed to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[363]

2. Comments

a. General Comments

145. The majority of commenters support the Commission's proposal,[364] with multiple commenters claiming that Long-Term Regional Transmission Planning is crucial to ensure that regional transmission planning appropriately identifies transmission needs to meet the changing resource mix and demand.[365]

146. AEP and Ørsted argue that the Commission's proposal will address deficiencies in the current transmission planning process.[366] National Grid claims that existing long-term transmission planning processes are sufficient for addressing reliability and economic transmission needs in the near-term but are inadequate for addressing the changing resource mix and demand, as well as for addressing resilience challenges driven by climate change.[367] ACEG claims that Long-Term Regional Transmission Planning will allow right-sizing of transmission facilities.[368]

147. Some commenters observe that this proposal may result in cost-savings for consumers. For example, DC and MD Offices of People's Counsel claim that this proposal could result in significant cost savings to consumers by helping address severe weather events and reduce the relative cost of decarbonizing the country's resource fleet.[369] AEP argues that the NOPR proposal will benefit consumers by establishing a process that will identify more efficient or cost-effective transmission facilities, capturing currently missed opportunities and achieving economies of scale.[370] North Carolina Commission and Staff argue that Long-Term Regional Transmission Planning can provide state utility commissions and consumer advocates with useful information to promote a cost-effective and reliable transmission grid.[371]

148. NextEra states that Long-Term Regional Transmission Planning can minimize overall costs to consumers by enabling the lowest-cost generation.[372] Relatedly, Tabors Caramanis Rudkevich states that the NOPR proposal would establish a transmission planning process that coordinates across franchises, states, and regions, which will reduce the production cost of delivery of energy to consumers.[373]

149. PPL notes that Long-Term Regional Transmission Planning may improve some of the limitations of criteria-based transmission planning, which is currently employed in RTOs/ISOs.[374] Ørsted supports the proposed requirements regarding Long-Term Regional Transmission Planning and argues that existing regional transmission plans fail to anticipate the size and scale of future offshore wind generation development, leading to inaccurate plans and insufficient investment in infrastructure needed to integrate known future offshore wind generation.[375]

150. State Agencies assert that the Commission's various proposed reforms in the NOPR collectively would enhance transparency, prevent unnecessary investment in local transmission projects, and improve the competitive landscape.[376] US DOJ and FTC support reforms that address obstacles to transmission development and that are implemented consistent with principles for competition.[377]

b. Requests for Flexibility in Transmission Planning

151. A number of commenters support the Commission's proposal to require Long-Term Regional Transmission Planning, but also express reservations or objections regarding what they perceive as an overly prescriptive approach that may disrupt existing processes that are already working.[378] For example, multiple

[362] *Id.* P 75.

[363] *Id.* P 76.

[364] Acadia Center and CLF Initial Comments at 2; ACEG Initial Comments at 6, 22–23; ACORE Initial Comments at 2, 17; Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 5–7; Amazon Initial Comments at 2; BP Initial Comments at 4–7; Breakthrough Energy Initial Comments at 3; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2–4; California Energy Commission Initial Comments at 1; City of New Orleans Council Initial Comments at 4; City of New York Initial Comments at 1, 3; Clean Energy Associations Initial Comments at 10; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy—Florida Supplemental Comments at 1; Conservatives for Clean Energy—South Carolina; CTC Global Initial Comments at 1; US Senators Supplemental Comments at 1–2; EEI Initial Comments at 10; ELCON Initial Comments at 6–7; NERC Initial Comments at 6–7; ENGIE Initial Comments at 2; Entergy Initial Comments at 7; Environmental Groups Supplement Comments at 2; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 2; Exelon Initial Comments at 4–7; Form Energy Initial Comments at 2–3; Governor of Kansas Laura Kelly Supplemental Comments at 1; Handy Law Initial Comments at 7–8; US House Republicans Supplemental Comments at 1; Indicated PJM TOs Initial Comments at 7–8; Indicated US Senators and Representatives Initial Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; ISO–NE Initial Comments at 2, 8; ITC Initial Comments at 5–9; Joint Consumer Advocates Initial Comments at 5–6; Minnesota State Entities Initial Comments at 4; NARUC Initial Comments at 4; National Grid Initial Comments at 9–11; NEMA Initial Comments at 1–2; NESCOE Initial Comments at 14–16; New England for Offshore Wind Initial Comments at 2; New York Commission and NYSERDA Initial Comments at 8; New York TOs Initial Comments at 1; New York Transco Initial Comments at 1; NextEra Initial Comments at 62; Northwest and Intermountain Initial Comments at 7; Ohio Conservative Energy Forum Supplemental Comments at 1; Pine Gate Initial Comments at 18–19; PIOs Initial Comments at 12–14; Policy Integrity Initial Comments at 5; RMI Supplemental Comments at 2; Senator Schumer Supplemental Comments at 1–2; Senator Whitehouse Supplemental Comments at 1–3; SDG&E Initial Comments at 2; Southeast PIOs Initial Comments at 42–49; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 1–2; Vermont Electric and Vermont Transco Initial Comments at 3; Virginia Commission Staff Initial Comments at 2–3; Western PIOs Initial Comments at 28–30, 36; Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[365] Breakthrough Energy Initial Comments at 12; EEI Supplemental Comments at 1; Exelon Initial Comments at 5; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 5.

[366] AEP Initial Comments at 8; Ørsted Initial Comments at 4–5.

[367] National Grid Initial Comments at 10.

[368] ACEG Initial Comments at 6.

[369] DC and MD Offices of People's Counsel Initial Comments at 8–10 (citing Patrick Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System,* 5 Joule 115, 115–134 (2020), *https://www.sciencedirect.com/science/article/pii/S2542435120305572?dgcid=author%20_blank*); *see also* EEI Supplemental Comments at 1 (arguing that robust transmission development will provide cost savings from greater access to low-cost resources).

[370] *See* AEP Initial Comments at 8–12.

[371] North Carolina Commission and Staff Initial Comments at 4.

[372] NextEra Initial Comments at 62.

[373] Tabors Caramanis Rudkevich Initial Comments at 4–5.

[374] PPL Initial Comments at 4. PPL claims that, while PJM may perform long-term transmission planning on a 15-year time frame on paper, its long-term transmission planning is effectively undertaken over only 7 to 10 years. *Id.*

[375] Ørsted Initial Comments at 4–5.

[376] State Agencies Reply Comments at 6.

[377] US DOJ and FTC Initial Comments at 19.

[378] *See, e.g.,* Avangrid Initial Comments at 6, 9; CAISO Initial Comments at 1–2, 7–10, 13; California Commission Initial Comments at 6; Duke Initial Comments at 1–2; Indiana Commission Initial Comments at 1, 3; ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028 at PP 66, 104); Massachusetts Attorney General Initial Comments at 10–12; Michigan Commission Initial Comments

Continued

commenters express concerns that the NOPR's allegedly prescriptive requirements for Long-Term Regional Transmission Planning will significantly limit needed discretion to conduct such planning, and that, without discretion to adjust the scenario modeling and assumptions to regional circumstances, the final order could lead to more delay and conflict.[379] MISO TOs contend that the NOPR proposals vary sufficiently from MISO's current approach that MISO and its stakeholders will need to engage in complex and time-intensive revisions in order to comply.[380] Similarly, City of New Orleans Council asks that the final order not hinder existing MISO processes.[381]

152. Multiple commenters recommend that the Commission's final order establish principles and objectives for long-term transmission planning that address the Commission's concerns and provide transmission providers with the flexibility to develop tailored long-term transmission planning approaches and implementation details accordingly.[382] MISO recommends that each transmission provider should give the Commission a report outlining the actions and processes that support the Commission's principles and guidance, and then the Commission could direct specific changes within each transmission planning region as it deems necessary.[383]

153. Multiple commenters argue for flexibility to accommodate local and regional differences, including differences in public policy goals that affect transmission planning.[384] NYISO asks that the final order give each transmission planning region discretion to determine, in coordination with state entities and stakeholders, how best to incorporate the Long-Term Regional Transmission Planning requirements within its transmission planning framework.[385] California Municipal Utilities add that a significant amount of demand in the West is served by publicly-owned utilities and electric cooperatives, which fall outside of state commission regulation, highlighting the need for flexibility in planning.[386]

154. Dominion asserts that any reforms adopted in this proceeding should align with the purpose of the transmission system, which is to provide reliable, affordable electric service to customers rather than to benefit generators.[387]

155. APPA agrees with concerns expressed by Commissioner Christie and former Commissioner Danly that overly prescriptive transmission planning requirements have the potential to interfere with existing regional transmission planning processes, and hence argues that adequate flexibility is needed.[388] Mississippi Commission states that where an RTO/ISO or non-RTO/ISO transmission provider is already engaged in long-term regional transmission planning, the Commission should accept flexibility and regional variations on compliance to address region-specific issues, including the delineation of regional and local transmission facilities through, for example, a voltage threshold (*e.g.,* 100 kV).[389]

156. CAISO maintains that the Commission should allow it to continue evaluating transmission needs driven by Public Policy Requirements in its transmission planning process, in addition to any Long-Term Regional Transmission Planning process, and give CAISO the flexibility to continue using resource portfolios and geographic zones identified by state agencies and local regulatory authorities.[390] Although ACORE urges the Commission not to grant requests for less stringent transmission planning requirements in the final order, ACORE agrees that there may be cases where an individual RTO's/ISO's existing processes may be superior to the proposed reforms, such as in the case of CAISO's treatment of public policy projects within its annual transmission planning process.[391] California Municipal Utilities note that CAISO has already begun to implement some of the key reforms that the Commission proposed in the NOPR, specifically by adopting a 20-year outlook for transmission planning.[392]

157. MISO requests that a final order support, rather than detract from, its demonstrated success in long-term transmission planning.[393] MISO TOs request that the Commission revise the NOPR's required parameters for Long-Term Regional Transmission Planning to accommodate the robust long-term regional transmission planning that some transmission planning regions, like MISO, have already developed.[394] Similarly, Ameren contends that the Commission should find that MISO's approved Long Range Transmission Planning process substantially complies with the proposed reforms.[395]

158. New York TOs support allowing transmission planning regions with already successful transmission planning processes to retain those processes while making incremental enhancements and to demonstrate on compliance that they meet the NOPR's objectives.[396] New York Transco asserts that the current NYISO public policy transmission planning processes already address, at least in part, the proposed reforms and believes that the Commission should permit regional flexibility.[397]

159. SPP states that its current transmission planning processes are sufficient to meet the intent of the Commission's proposed Long-Term Regional Transmission Planning reforms.[398] Omaha Public Power states that SPP and other RTOs/ISOs have already developed long-term planning scenarios and suggests that transmission providers that already have long-term planning scenarios should be provided with the flexibility to continue using their previously established processes.[399]

160. In contrast, some commenters argue that the final order should not provide too much flexibility to transmission providers because that flexibility will undermine Long-Term

at 4–5; MISO Initial Comments at 23; NEPOOL Initial Comments at 7; NYISO Initial Comments at 11; PG&E Initial Comments at 2; PJM Initial Comments at 54–55; US Chamber of Commerce at 4–5.

379 Ameren Initial Comments at 8; ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8–9; MISO TOs Reply Comments at 10–12.

380 MISO TOs Reply Comments at 10–11.

381 City of New Orleans Initial Comments at 5–6.

382 ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4–5, 8–9; MISO Initial Comments at 22–23.

383 MISO Initial Comments at 22.

384 APPA Reply Comments at 9–10; California Commission Initial Comments at 5; California Municipal Utilities Reply Comments at 2–4; Industrial Customers Reply Comments at 4; Louisiana Commission Reply Comments at 4–5; Georgia Commission Initial Comments at 2; NARUC Initial Comments at 3; New York Transco Initial Comments at 5; North Dakota Commission Initial Comments at 3; New York Commission and NYSERDA Initial Comments at 3; OMS Initial Comments at 3; PJM States Initial Comments at 2.

385 NYISO Initial Comments at 13.

386 California Municipal Utilities Reply Comments at 2.

387 Dominion Initial Comments at 5.

388 APPA Initial Comments at 23.

389 Mississippi Commission Reply Comments at 7–8 (citing Entergy Initial Comments at 2–4; Louisiana Commission Initial Comments at 35–36; Michigan State Entities Initial Comments at 2; MISO Initial Comments at 2–3, 19; MISO TOs Initial Comments at 2, 4, 13–15).

390 CAISO Reply Comments at 17–18.

391 ACORE Reply Comments at 4.

392 California Municipal Utilities Initial Comments at 5.

393 MISO Reply Comments at 2–3.

394 MISO TOs Reply Comments at 11–12.

395 Ameren Initial Comments at 8.

396 New York TOs Initial Comments at 8–9.

397 New York Transco Initial Comments at 5.

398 SPP Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 3).

399 Omaha Public Power Initial Comments at 4.

Regional Transmission Planning.[400] Many commenters opposing greater flexibility argue that the Commission should establish minimum requirements for Long-Term Regional Transmission Planning.[401]

161. AEP argues that the Commission must resist requests for excessive regional flexibility that could threaten the development of long-term regional transmission and only permit it in limited instances that exceed minimum requirements.[402] Onward Energy states that, while flexibility is reasonable, the Commission must clearly identify who will drive regional transmission planning processes and how transmission planners will coordinate, study, and implement Long-Term Scenarios that represent realistic future resource portfolios.[403] Clean Energy Associations state that without robust and proactive transmission planning rules, the Commission cannot determine that rates remain just and reasonable.[404] DC and MD Offices of People's Counsel state that, while regional flexibility is critical, long-term transmission planning rules that provide carve-outs and opt-outs will result in balkanized transmission development.[405]

162. Hannon Armstrong states that by diluting the proposed requirements or granting flexibility as some commenters request, the Commission would allow existing deficiencies to persist, enabling the continued reliance on either the generator interconnection process or operational planning to resolve or mitigate constraints.[406] Invenergy rebuts commenters' claims that the NOPR is too prescriptive or that some of the NOPR requirements should be optional, stating that optional processes and deference to regional flexibility will not ensure needed transmission is built and that a flexible approach has already been tried and has failed to produce sufficient results.[407]

c. Comments Regarding More Comprehensive Transmission Planning

163. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and should not supplant existing shorter-term transmission planning processes.[408] PJM asks the Commission to confirm that it did not mean for the NOPR proposals on Long-Term Regional Transmission Planning to modify the existing reliability and market efficiency transmission planning processes.[409] Transmission Dependent Utilities encourage the Commission to ensure that transmission providers do not focus on long-term objectives to satisfy state renewable energy portfolio requirements to the detriment of near-term reliability needs, such as end-of-life transmission planning.[410] Large Public Power and NEPOOL state that any final order should clearly state that the current near-term transmission planning rules and processes, especially cost allocation, are not changed by the final order's reforms, except where expressly indicated.[411] Ameren argues that the Commission was clear that changes to existing reliability and economic transmission planning requirements are beyond the scope of the NOPR and that the comments filed supporting holistic planning have provided no compelling basis for the Commission to address them.[412]

164. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and must not supplant existing shorter-term transmission planning processes for transmission needs driven by Public Policy Requirements.[413] CAISO states that the NOPR provides no guidance or criteria regarding how a transmission provider can demonstrate that its existing process for addressing transmission needs driven by Public Policy Requirements does not interfere with or undermine Long-Term Regional Transmission Planning. CAISO contends that it should not have to re-justify its existing process or demonstrate that its existing process is consistent with or superior to Long-Term Regional Transmission Planning.[414]

165. AEP asserts that transmission providers should look at nearer-term reliability and economic transmission planning processes to determine whether there are needs that can be incorporated into Long-Term Regional Transmission Planning and addressed by a Long-Term Regional Transmission Facility.[415] SEIA recommends that the Commission require transmission providers to engage in portfolio-based transmission planning that integrates all relevant factors, including near-term needs, into Long-Term Regional Transmission Planning.[416] Policy Integrity argues that inclusion of specific requirements for transmission modeling are needed to fulfill the mandate of ensuring wholesale electric rates are just and reasonable.[417] Xcel recommends that the Commission require that known or expected generation be included in short-term regional transmission planning assumptions.[418]

166. PIOs state that, if the two processes continue to exist, the Commission should mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process. Otherwise, PIOs contend, inconsistent assumptions between the two processes could lead to redundant transmission projects and failure to identify more efficient solutions. In particular, PIOs argue, if an Order No. 1000 transmission planning process base case identifies transmission needs that are not anticipated in the Long-Term Scenarios, the opportunities for more efficient planning created by the long-term process will be lost. In addition, PIOs suggest that there may be opportunities for stakeholders to undermine Long-Term Regional Transmission Planning if they believe Order No. 1000 transmission planning

[400] *See, e.g.,* ACORE Reply Comments at 2–4 (citing New Jersey Commission Initial Comments at 7); AEP Reply Comments at 2–5; Clean Energy Associations Reply Comments at 4–6; DC and MD Offices of People's Counsel Reply Comments at 2–3; Hannon Armstrong Reply Comments at 1; Interwest Reply Comments at 3–4; Invenergy Reply Comments at 8–10; PIOs Reply Comments at 5–6.

[401] *See, e.g.,* AEE Reply Comments at 9–13, 16–18, 21–22; AEP Reply Comments at 2–5; Cypress Creek Reply Comments at 4–9; Interwest Reply Comments at 3–4; Invenergy Initial Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 2; PIOs Reply Comments at 2–3; SEIA Reply Comments at 1–3; Southeast PIOs Reply Comments at 21–22; SREA Reply Comments at 26–27.

[402] AEP Reply Comments at 3.

[403] Onward Energy Initial Comments at 4.

[404] Clean Energy Associations Reply Comments at 4–5 (citing CAISO Initial Comments at 3; California Commission Initial Comments at 11; ISO-New England Initial Comments at 4; ISO/RTO Council Initial Comments at 8; NYISO Initial Comments at 3; PG&E Initial Comments at 4; PJM States Initial Comments at 4).

[405] DC and MD Offices of People's Counsel Reply Comments at 2.

[406] Hannon Armstrong Reply Comments at 1.

[407] Invenergy Reply Comments at 9–10.

[408] Ameren Reply Comments at 17; CAISO Initial Comments at 2–3, 17–20; Chemistry Council Initial Comments at 5; Dominion Initial Comments at 23; Exelon Initial Comments at 6–7; Indicated PJM TOs Initial Comments at 12; ITC Initial Comments at 8–9; Large Public Power Initial Comments at 14–16; NEPOOL Initial Comments at 8; NESCOE Initial Comments at 21–23; PJM Initial Comments at 55–57; PPL Initial Comments at 4–5; Transmission Dependent Utilities Initial Comments at 4–6; WIRES Initial Comments at 6–7; Xcel Initial Comments at 16.

[409] PJM Initial Comments at 55–57.

[410] Transmission Dependent Utilities Initial Comments at 4–6.

[411] Large Public Power Initial Comments at 16–18; NEPOOL Initial Comments at 7–8.

[412] Ameren Reply Comments at 17.

[413] Anbaric Initial Comments at 22–27; CAISO Initial Comments at 2–3, 9–20; Large Public Power Initial Comments at 14–16.

[414] CAISO Initial Comments at 19.

[415] AEP Initial Comments at 10.

[416] SEIA Initial Comments at 20–21.

[417] Policy Integrity Supplemental Comments at 3.

[418] Xcel Initial Comments at 16.

would produce more favorable results for them. PIOs further argue that because uncertainty grows the further one looks into the future, there should not be significant differences in the short-term results of Long-Term Regional Transmission Planning and Order No. 1000 regional transmission planning processes.[419]

167. Several commenters support forward-looking, Long-Term Regional Transmission Planning but argue for holistic planning using multiple drivers of transmission needs.[420] They argue that a holistic approach is more efficient, better accounts for long-term benefits of new transmission, addresses the needs of more stakeholders, and is more likely to support development of regional transmission facilities, among other benefits. Competition Advocates support a final order that reflects the benefits of holistic modeling,[421] while New Jersey Commission contends that holistic transmission planning using a competitive process provides significant benefits, including reducing costs.[422]

168. To ensure that reforms are not undermined by existing processes, Clean Energy Buyers recommend that the Commission extend to all existing regional transmission planning processes—not just transmission planning processes to address transmission needs driven by Public Policy Requirements, as proposed in the NOPR—the requirement that, on compliance with any final order, transmission providers who seek to retain existing regional transmission planning and cost allocation processes must demonstrate that continued use of those processes does not interfere with or undermine Long-Term Regional Transmission Planning.[423]

169. However, other commenters support the Commission's proposal in the NOPR to *not* apply the proposed reforms to existing Order No. 1000 reliability and near-term economic regional transmission planning processes.[424] Ohio Consumers support the NOPR's proposal to mostly retain the regional transmission planning processes outlined in Order No. 1000, explaining that PJM stakeholders have reached an effective settlement under that framework in which costs are allocated in a manner that is roughly commensurate with the benefits received.[425]

170. Some commenters argue that the Commission should require that local transmission projects be evaluated and approved as part of a holistic planning approach.[426] AEE asserts that, to ensure that transmission providers consider the full range of needs in developing long-term regional transmission plans, the final order should require them to consider local transmission plans and to determine whether a regional solution would be more efficient or cost-effective.[427] OMS suggests that the Commission require that all local transmission projects be evaluated and approved as part of regional transmission planning processes with the opportunity for meaningful input from retail regulators, which it argues will enable participation by state regulators while respecting transmission owners' abilities to maintain their systems.[428]

171. By contrast, WIRES argues that the Commission should maintain the distinction between regional transmission planning and local transmission planning. WIRES argues that, while the regional transmission planning process is directed toward addressing certain reliability concerns, economic criteria, and public policy initiatives, it is not geared toward addressing additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that is typically the focus of local transmission planning.[429] Similarly, AEP states that if an RTO/ISO were to make all decisions regarding local transmission projects, they would also need to assume the accompanying responsibility—and the liability—for such decisions, which would entail physical inspection and condition assessment of assets, as well as a determination of when transmission facilities have reached their end of useful life.[430] AEP points out that both CAISO and PJM have expressly stated that they do not wish to undertake these types of activities and assume such obligations.[431]

d. Concerns Regarding Favoring Renewable Resources

172. ELCON argues that the Commission's proposal could require customers to pay higher costs to connect distant renewables when a lower-cost transmission project would provide the same reliability or economic benefits.[432] Utah Division of Public Utilities states that Long-Term Scenario requirements favoring renewable generation burden transmission providers while providing little to no benefit and that developers and generation utilities should determine which renewable generation should be developed at their respective zones or sites.[433] Utah Commission further contends that nationwide mandates for transmission planning add costs, produce confusion, and create conflicts that could lead to higher utility prices for consumers.[434] Kansas Ratepayer Advocates contend that Long-Term Regional Transmission Planning would presume material additions of renewable energy to serve consumers within a state, coupled with material additions of transmission to interconnect those renewables to the electric transmission grid, which do not reflect the unique circumstances of Kansas.[435]

173. Vistra asserts that the proposed reforms could devolve into the subsidization of resources chosen to

[419] PIOs Initial Comments at 44–46.

[420] *See, e.g.,* Acadia Center and CLF Initial Comments at 4–7; ACEG Initial Comments at 6–7, 30–31; ACORE Initial Comments at 5–7; Anbaric Initial Comments at 5–10; AEE Reply Comments at 2; Business Council for Sustainable Energy Initial Comments at 2; City of New York Initial Comments at 4–6; Competition Coalition Initial Comments at 15–16; Cypress Creek Reply Comments at 4–5; Enel Initial Comments at 3; Pine Gate Initial Comments at 18–19; PIOs Reply Comments at 11; SEIA Reply Comments at 2, 7–8; *see also* Pattern Energy Initial Comments at 16.

[421] Competition Advocates Supplemental Comments at 1; *see also* Policy Integrity Supplemental Comments at 2–3 (citing Jennifer Danis *et al.,* Inst. for Policy Integrity, *Transmission Planning for the Energy Transition: Rethinking Modeling Approaches* (Dec. 2023), *https://policyintegrity.org/files/publications/Transmission_Report_2023.pdf*).

[422] New Jersey Commission Motion to Lodge at 4–5 (citing *In re Declaring Transmission to Support Offshore Wind a Pub. Policy of the State of N.J.,* Order on the State Agreement Approach SAA Proposals, N.J. BPU Docket No. QO20100630 (Oct. 26, 2022), *https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279919;* Johannes P. Pfeifenberger, et al., Brattle Grp., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report,* (Oct. 26, 2022), *https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279916;* PJM, *Economic Analysis Report: 2021 SAA Proposal Window to Support NJ OSW* (Nov. 4, 2022), *https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221104-special/informationalonly---njosw-economic-analysis-report.ashx*).

[423] Clean Energy Buyers Initial Comments at 9–10.

[424] Ameren Reply Comments at 17; Exelon Initial Comments at 6–7; ITC Initial Comments at 8–9; WIRES Initial Comments at 6–7.

[425] Ohio Consumers Initial Comments at 7 (citing NOPR, 179 FERC ¶ 61,028 at P 72).

[426] AEE Initial Comments at 3, 38; OMS Initial Comments at 16–17; LS Power and NRG Supplemental Comments at 34–37.

[427] AEE Initial Comments at 3, 38.

[428] OMS Initial Comments at 16–17.

[429] WIRES Initial Comments at 9.

[430] AEP Reply Comments at 7.

[431] *Id.* (citing *S. Cal. Edison Co.,* 164 FERC ¶ 61,160, at P 18 (2018); PJM Interconnection, L.L.C., Comments of PJM, Docket No. ER20–2308–000, at attach. A (July 2, 2020) (citation omitted)).

[432] ELCON Initial Comments at 9–10.

[433] Utah Division of Public Utilities Initial Comments at 7–8.

[434] Utah Commission Initial Comments at 11, 13.

[435] Kansas Ratepayers Advocates Reply Comments at 2.

achieve state policy goals, masking the true costs of those remotely located resources that require extensive transmission development to interconnect to the grid and leading to market distortions that undermine the objectives of these reforms.[436]

174. Louisiana Commission states that the NOPR would result in subsidization of the costs of transmitting remote renewable energy, spreading the costs out broadly based on an expanded ''nebulous concept of 'benefits' and perceived 'public policy,' '' thus ensuring that those transmission projects will pass any economic test.[437] According to Louisiana Commission, this subsidization would interfere with price signals, thereby distorting the efficient functioning of the wholesale market.[438] Louisiana Commission states that any Commission policy should be resource and technology neutral and should not impose costs on states that do not benefit from distant renewable power.[439]

175. Finally, Louisiana Commission contends that the NOPR's long-term transmission planning requirements could threaten the reliability of the transmission grid because the intermittent renewable resources that the NOPR favors do not provide stable output and are not dispatchable.[440] Similarly, former Kansas Commission Chair Keen argues that the NOPR fails to acknowledge the reliability concerns associated with a generation mix that is too heavily weighted to intermittent renewable generation resources.[441]

e. Concerns Regarding Uncertainty, Over-Building, and Costs

176. A few commenters argue that long-term transmission planning introduces uncertainty or incentivizes speculative transmission development.[442] While EPSA acknowledges that long-term forecasts can provide valuable information about the potential scale of construction necessary to achieve decarbonization, it argues that using such forecasts to justify investment shifts the risks to consumers from developers and facility owners.[443] California Municipal Utilities state that, as transmission planning horizons are extended, the changes in resource mix, technology types, the location of resources, and demand will likely change congestion patterns and therefore the need for transmission upgrades needed to address them.[444]

177. Louisiana Commission states that it opposes the NOPR proposal because it would lead to an inefficient and expensive build-out of the transmission system and could be used to justify shifting the costs of this build-out to load.[445] ELCON states that it is concerned that the Commission's proposal to prioritize Long-Term Regional Transmission Planning to connect renewable generation over Long-Term Regional Transmission Planning for economically necessary transmission may exceed the Commission's authority if it increases transmission rates for the benefit of a few stakeholders.[446] Southern states that transmission expansion predicated on hypothetical resources that might not materialize would not satisfy the fundamental legal requirements of being used and useful, prudent, and/or otherwise needed for the public use, could harm reliability, and would violate the Commission's duty under the FPA to facilitate transmission planning to meet load-serving entities' obligations.[447]

178. Industrial Customers argue that the NOPR does not provide evidence that extending the transmission planning horizon would exclude modeling of speculative projects, which would likely result in the over-building of transmission and unnecessary increases in rates.[448] Industrial Customers cite the D.C. Circuit's finding in *Old Dominion Electric Cooperative* v. *FERC* that ''[w]e are sensitive to the concern . . . that individual utilities should not have free rein to impose unjustified costs on an entire region by unilaterally adopting overly ambitious planning criteria,'' and argue that the current NOPR proposal would result in the same issues.[449]

179. NRG urges caution on over-reliance on any 20-year planning study for making transmission investments due to the inherent uncertainty of a study with such a long planning horizon.[450] NRG argues that the NOPR will increase delivery costs by reducing the value of private investments and replacing such investments with a centrally planned, cost-socialized approach that is founded on at least some incorrect assumptions.[451] NRG provides several examples of how forecast errors have caused adverse consequences, including forecasts of natural gas prices, load forecasts, and canceled planned transmission facilities.[452]

180. Likewise, Ohio Consumers urge the Commission to avoid adopting proposals based on long-term projections that justify massive charges to consumers based on hypothetical scenarios.[453] Ohio Consumers state that Ohio customers have recently been saddled with rate increases in part due to transmission investments and that long-term transmission planning requirements would increase ratepayer burden, which is especially troublesome if projections turn out to be inaccurate.[454]

181. As an alternative to Long-Term Regional Transmission Planning, Potomac Economics states that the Commission could require the transmission planning process to incorporate a broader array of near-term emerging trends that are less uncertain than the proposed longer-term factors.[455] Louisiana Commission states that it shares Potomac Economics' concerns. Louisiana Commission urges the Commission to heed testimony submitted by Potomac Economics arguing that: (1) there is significant uncertainty about future technology and a significant risk of investing in transmission projects that will not ultimately provide value; (2) large transmission projects are often not the most economic, whereas smaller, targeted projects are more beneficial; and (3) there can and likely would be stranded transmission if transmission planning processes attempt to identify and meet transmission needs 20 to 30 years in the future.[456]

182. US Chamber of Commerce argues that the Commission should ensure that any Long-Term Regional Transmission

[436] Vistra Initial Comments at 11.

[437] Louisiana Commission Reply Comments at 12 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 2)).

[438] Louisiana Commission Initial Comments at 19–21.

[439] *Id.* at 21–24.

[440] *Id.* at 21–23. *But see* Cypress Creek Reply Comments at 2–4 (disagreeing with Louisiana Commission and claiming that regionally coordinated transmission planning should provide demonstrable system reliability benefits).

[441] Kansas Commission Chair Keen Initial Comments at 1.

[442] EPSA Initial Comments at 7; New England Systems Initial Comments at 22; *see also* NRECA Initial Comments at 28–29.

[443] EPSA Initial Comments at 7.

[444] California Municipal Utilities Initial Comments at 7.

[445] Louisiana Commission Initial Comments at 4–5.

[446] ELCON Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 (Danly, Comm'r, dissenting, at P 2 n.3); NOPR, 179 FERC ¶ 61,028 at P 47).

[447] Southern Initial Comments at 32, 34.

[448] Industrial Customers Initial Comments at 6, 15–16, 19–21.

[449] *Id.* at 16 (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d 1254, 1263 (D.C. Cir. 2018)).

[450] NRG Initial Comments at 8.

[451] *Id.* at 3.

[452] *Id.* at 10–11.

[453] Ohio Consumers Initial Comments at 5.

[454] *Id.*

[455] Potomac Economics Initial Comments at 4.

[456] Louisiana Commission Reply Comments at 13–14.

Planning reforms do not perpetuate an irrational transmission buildout that undermines competitive advantages of domestic electricity rates. US Chamber of Commerce asserts that the loss of competitive advantage would lead to lost jobs, lost economic growth, decreased electricity use, and fixed system costs assessed to fewer customers.[457]

183. Vistra states that the proposed reforms lean toward accounting for regulatory and public policy initiatives that may shape changes in the generation mix without sufficiently incorporating the commercial and markets-related aspects of generation development.[458] Vistra states that, without a process to assess commercial interest and financial commitment from generation developers, long-term regional transmission plans may under- or over-build transmission facilities or build them in the wrong locations.[459] Relatedly, NRECA states that planning a regional transmission network for generation resources or changes in demand not identified by load-serving entities' forecasts, and instead through unsupported top-down assumptions, may produce uneconomic results from over-building and increase reliability risks.[460]

184. NRG states that, in light of the uncertainty of variables such as the amount of electrification and resulting load requirements, technology costs for new resources, and viability and repurposing of existing resources, it is not clear whether a ''no regrets'' option genuinely exists. NRG also asserts that the centralized planning envisioned in the NOPR sacrifices the ability of market participants to use available information to assess whether their investments will be viable in the future, which is a critical feature of competition. NRG asserts that the Commission has not contemplated that trade-off or quantified its costs, noting that past long-term transmission planning studies have done a questionable job at forecasting future needs.[461]

185. Other commenters, however, note that the NOPR proposal includes measures that mitigate the uncertainty inherent in longer-term regional transmission planning.[462] For example, New Jersey Commission states that the proposed requirements to develop multiple scenarios and perform reassessments mitigates the uncertainty inherently present in a 20-year transmission planning horizon.[463] Additionally, several commenters rebut opposition to Long-Term Regional Transmission Planning based on concerns that it presents unreasonable levels of uncertainty.[464] For example, SREA and Clean Energy Buyers assert that periodic updates of forecasts and scenarios will help to mitigate uncertainty.[465]

186. Policy Integrity further explains that future uncertainty is exactly why long-term scenario planning is necessary to ensure just and reasonable rates. Policy Integrity states that the current transmission planning process uses deterministic modeling that does not account for the changing world, which will not lead to the development of efficient or cost-effective transmission solutions. Policy Integrity asserts that, in contrast, long-term scenario planning will allow transmission planners to be prepared for changes.[466] Policy Integrity argues that any forward-looking decision will have a degree of uncertainty, but that the risk posed by uncertainty can be mitigated and managed by using a portfolio evaluation of costs and benefits.[467] Policy Integrity further argues that ignoring the uncertainty surrounding the energy transition runs its own risk of failing to build transmission that can be useful to meet needs in the short, medium, and long term.[468]

f. Concerns Regarding Incentives for Resource Development

187. Vistra asserts that it is critical for Commission policy to maintain interconnection cost signals to drive cost-effective generation siting choices.[469] Vistra also argues that a policy that assigns all interconnection-related network upgrade costs, or even a disproportionately high share, to load undermines the incentive that generation developers currently have to site new projects in locations that minimize the related transmission upgrade costs.[470]

188. In contrast, New Jersey Commission argues that requiring individual interconnecting generators to pay for piecemeal interconnection-related network upgrades does not necessarily encourage developers to make siting decisions that minimize the overall cost of integrating large amounts of new generation.[471] Likewise, Clean Energy Associations state that robust, proactive regional transmission planning will better incent efficient siting decisions, because generators will evaluate the likely costs of interconnection facilities that ensure deliverability to the grid, rather than more broadly beneficial transmission facilities.[472]

g. Comments Regarding Definition of Long-Term Regional Transmission Facility

189. PJM states that the Commission should clarify certain details of the NOPR proposal, including the meaning of the word ''identified'' in the proposed definition of Long-Term Regional Transmission Facility.[473] In addition, PJM requests that the Commission clarify that if a transmission project shows up in several Long-Term Scenarios but is not selected until it reaches one of the shorter-term reliability and market efficiency transmission planning processes, that project would not be considered a Long-Term Regional Transmission Facility for selection and cost allocation purposes.[474] Otherwise, PJM contends, the rules for selection and cost allocation for transmission projects selected in the shorter-term and intermediate-term reliability and market efficiency transmission planning processes will be unclear, leading to re-litigation.[475]

h. Challenges to Commission Jurisdiction or Authority

i. FPA Section 201

190. Some commenters argue that the NOPR proposals exceed the Commission's jurisdiction or that the Commission otherwise lacks the authority to adopt a final order in this proceeding. Of these commenters, most contend that the NOPR proposal interferes with authority reserved to the states under FPA section 201.[476]

[457] US Chamber of Commerce Initial Comments at 8.

[458] Vistra Initial Comments at 7.

[459] *Id.*

[460] NRECA Initial Comments at 18–19.

[461] NRG Initial Comments at 8.

[462] New Jersey Commission Initial Comments at 10–11; PIOs Initial Comments at 15–16.

[463] New Jersey Commission Initial Comments at 10–11.

[464] Clean Energy Buyers Reply Comments at 8; Policy Integrity Reply Comments at 2; SREA Reply Comments at 21–24.

[465] Clean Energy Buyers Reply Comments at 8; SREA Reply Comments at 23.

[466] Policy Integrity Reply Comments at 2.

[467] *Id.* at 3–4.

[468] *Id.* at 4.

[469] Vistra Initial Comments at 7.

[470] *Id.* at 7–8.

[471] New Jersey Commission Reply Comments at 7.

[472] Clean Energy Associations Reply Comments at 9 (citing ACEG 2021 Interconnection Report at 15).

[473] PJM Initial Comments at 8, 98.

[474] *Id.* at 99.

[475] *Id.* at 99, 101.

[476] Alabama Commission Initial Comments at 3–4, 7–8; Kansas Ratepayer Advocates Reply Comments at 2–3; Louisiana Commission Initial Comments at 5, 8–9, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3, 5–6; Mississippi Commission Reply Comments at 2; Nevada Commission Initial

191. Some commenters argue that the NOPR proposal intrudes on the authority reserved to the states under FPA section 201 over integrated resource planning processes or resource mix decision making.[477] For example, Alabama Commission states that the NOPR proposal for Long-Term Regional Transmission Planning would intrude on state integrated resource planning to the extent that it dictates the construction of facilities through a top-down regional process or seeks to influence or mandate a substantive change to the generation resource mix.[478] Similarly, Nevada Commission argues that the NOPR may impact states' authority to determine their own mix of generating resources. Nevada Commission contends that the NOPR may cross the line from regulating interstate transmission to regulating intrastate processes—particularly because the Commission has not asserted jurisdiction over bundled retail transmission.[479] Louisiana Commission argues that the Commission should not override state jurisdiction on resource planning, fuel type, and siting decisions, along with the regulation of retail rates.[480]

192. Mississippi Commission requests that the Commission acknowledge that it cannot force regional planning entities to indirectly act as a national integrated resource planner.[481] SERTP Sponsors and Southern argue that the NOPR essentially constitutes a Commission-regulated integrated resource plan/request for proposal process and that, to be workable, Long-Term Regional Transmission Planning instead must be based on state commission-regulated integrated resource planning/request for proposal decisions.[482] SERTP Sponsors and Southern contend that the NOPR proposed to require transmission providers to make independent resource and load decisions because: (1) state integrated resource plans are just one of many factors to be considered in developing Long-Term Scenarios; and (2) state integrated resource planning or request for proposal processes generally use a 10-year planning horizon such that there are no state-approved resources for the second half of the NOPR's proposed 20-year transmission planning horizon.[483] SERTP Sponsors and Southern further argue that, in upholding Order No. 1000, the D.C. Circuit emphasized that the Commission was regulating the transmission planning process and not mandating any particular outcome, and that, if the Commission prescribes a process that supplants state decision making, it will have crossed the line into prescribing substantive outcomes and thus exceeded its jurisdiction.[484]

193. Ohio Commission Federal Advocate contends that the NOPR appears designed to target the achievement of narrow environmental policy objectives or the socialization of transmission costs, not to ensure reliability or foster just and reasonable rates.[485] Southern and Utah Commission state that the Commission has consistently recognized that the FPA does not allow the Commission to pick winners and losers when it comes to generation and argue that the Commission has no authority to favor one generation mix over another.[486] Similarly, Louisiana Commission, Kansas Ratepayer Advocates, and Undersigned States contend that the Commission lacks the statutory authority to dictate states' generation resource decisions. They argue instead that each state possesses such authority and is uniquely qualified to choose the generation resources that are needed to economically meet ratepayers' electric service needs within their states.[487]

194. SERTP Sponsors and Southern argue that, even if assumptions about the resource mix included in Long-Term Scenarios do not bind states, requiring transmission providers to develop Long-Term Scenarios that are predicated on particular resource assumptions effectively makes a substantive resource decision because it favors the assumed resource mix over others.[488] SERTP Sponsors and Southern contend that this is akin to the Commission attempting to accomplish indirectly what it could not directly.[489] SERTP Sponsors argue that the Commission should support the exercise of traditional state resource and infrastructure planning authority rather than supplant it.[490] North Carolina Commission and Staff argue that the use of the production cost savings benefit in Long-Term Regional Transmission Planning ''could conflict with state-jurisdictional resource decisions.'' [491]

195. Other commenters disagree with these contentions and argue that the NOPR proposal would not intrude on states' reserved authority over resource mix decision making or integrated resource plan processes.[492] Kentucky Commission Chair Chandler and SEIA argue that the NOPR's stated aim of reforming regional and interregional transmission planning processes does not foreclose states' decision making on generation.[493] ACEG contends that the NOPR does not propose or purport to regulate the electric supply mix and that the Commission is acting squarely within its authority under the FPA's cooperative federalism structure.[494] AEE notes that the Commission included integrated resource planning and utility load-serving planning as a factor driving transmission needs and argues that none of the requirements proposed by the Commission directly conflict with

Comments at 2–3, 6; SERTP Sponsors Initial Comments at 5, 15–19 & n.20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–8, 12–13, 15–24; Southern Reply Comments at 3, 6–7; Utah Commission Initial Comments at 7–9; Undersigned States Reply Comments at 2, 4–5.

[477] Alabama Commission Initial Comments at 3–4, 7–8; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8–9, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)); Nevada Commission Initial Comments at 2–3; SERTP Sponsors Initial Comments at 5, 15–19 & n.20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–8, 12–13, 15–24; Southern Reply Comments at 3, 6–7; Utah Commission Initial Comments at 7–9; Undersigned States Reply Comments at 2, 4–5.

[478] Alabama Commission Initial Comments at 3–4, 7–8.

[479] Nevada Commission Initial Comments at 2–3.

[480] Louisiana Commission Initial Comments at 27–28; Louisiana Commission Reply Comments at 14–15.

[481] Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)).

[482] SERTP Sponsors Initial Comments at 15–16; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 4–5, 7, 15–16; Southern Reply Comments at 6–7.

[483] SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 12–13.

[484] SERTP Sponsors Initial Comments at 19; Southern Initial Comments at 23–24 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

[485] Ohio Commission Federal Advocate Initial Comments at 4–6.

[486] Southern Initial Comments at 23 (citing *ISO New England Inc.,* 162 FERC ¶ 61,205, at P 26 (2018)); Utah Commission Initial Comments at 7–9.

[487] Louisiana Commission Initial Comments at 8–10 (citing *Monongahela Power Co.,* 40 FERC ¶ 61,256, at 61,861 (1987); *Pac. Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n,* 461 U.S. 190, 212 (1983)); Kansas Ratepayer Advocates Reply Comments at 2; Undersigned States Reply Comments at 2, 4–5 (citing *Pac. Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n,* 461 U.S. at 205).

[488] SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 19.

[489] SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 18.

[490] SERTP Sponsors Initial Comments at 17, 19; *see also* Undersigned States Reply Comments at 5, 8 (citing *Am. Gas Ass'n* v. *FERC,* 912 F.2d 1496, 1510 (D.C. Cir. 1990)).

[491] North Carolina Commission and Staff Initial Comments at 7.

[492] ACEG Reply Comments at 15; AEE Reply Comments at 23; New Jersey Commission Reply Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2–3.

[493] Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2–3.

[494] ACEG Reply Comments at 15.

integrated resource planning processes, require that integrated resource planning be conducted on a different timeline, or override resource planning efforts.[495] Likewise, Kentucky Commission Chair Chandler reiterates that Kentucky's integrated resource plans are not driving transmission planning processes in the state. He explains that integrated resource plans/requests for proposals are not the basis for generation investment decisions, but the state's requests for proposals seek generation proposals after the integrated resource planning process is complete and a need for generation is identified.[496] In response to Alabama Commission's arguments that the NOPR's proposed rules have the potential to encroach on state-jurisdictional integrated resource planning and resource procurement processes overseen by Alabama Commission, SREA contends that Alabama Commission in fact does not have a formal integrated resource planning process upon which the Commission could encroach.[497]

196. New Jersey Commission disagrees with commenters who argue that the Commission intends to impose a preferred resource mix on the Nation by overriding state choices and contends that such arguments are ''profoundly misconstruing'' the nature of the NOPR proposal and what the Commission aims to achieve.[498] Instead, New Jersey Commission argues that Long-Term Regional Transmission Planning would address transmission needs that are being driven by state policies, market decisions, and technological changes, all of which reflect consumer-driven demand for cleaner electricity.[499] New Jersey Commission contends that the NOPR proposal would ensure that transmission needs are reliably met at a total cost that is just and reasonable, which New Jersey Commission argues is required—not precluded—by the FPA.[500]

197. Some commenters argue that the NOPR proposal would intrude on authority over siting and construction of transmission facilities that is reserved to the states under FPA section 201.[501] For example, Southern argues that the FPA reserves transmission siting authority to the states and that the final order should not directly or indirectly interfere with this authority.[502] Alabama Commission argues that Long-Term Regional Transmission Planning would interfere with state authority to the extent it dictates the construction of facilities through a top-down regional process.[503] Kansas Ratepayer Advocates state that the Commission would exceed its authority and violate states' constitutional rights by ordering states to construct interregional transmission facilities with construction costs paid by retail ratepayers in Kansas.[504]

198. Nevada Commission explains that Nevada law governs the issuance of permits to construct transmission facilities, and that such facilities—even where their costs are not intended to be recovered through retail rates—must go through and may not bypass that process in favor of regional transmission planning processes.[505] NARUC contends that state participation in cost allocation for a portfolio of Long-Term Regional Transmission Facilities does not require a state, in its role as a transmission siting authority, to approve any projects within the portfolio.[506]

199. A few commenters argue that the NOPR proposal would intrude on the authority over certain transmission planning allegedly reserved to the states under FPA section 201. For example, Mississippi Commission states that the final order must respect state jurisdictional authority over planning and approval of transmission facilities used to serve state load.[507] Nevada Commission states that Nevada will continue to plan for transmission through its integrated resource planning process and that the Commission should allow ''bottom up'' transmission planning, particularly in non-RTO/ISO transmission planning regions.[508]

200. In contrast, other commenters express support for the Commission's role in transmission planning. Ohio Consumers argue that the Commission has authority over transmission planning, even in states like Ohio that allow for retail consumer choice.[509] SREA explains that states and other jurisdictional regulators will continue to have ultimate control over generation resource planning and transmission planning, regardless of what a regional transmission body proposes. SREA states that, even within RTO/ISO regions, ''transmission or generation resource plans are subject to review, update or even cancellation, and those decisions are always determined by the relevant regulatory bodies.'' [510] Vistra states that any final order should recognize the legal and practical boundaries on the Commission's role in transmission development and in shaping the generation sector. According to Vistra, the Commission has successfully relied on its general authority under FPA sections 205 and 206 to oversee rates, terms, and conditions of jurisdictional service as the basis for its policies on transmission planning.[511]

201. Finally, Mississippi Commission argues that the NOPR proposal may infringe upon states' reserved authority under FPA section 201 to make resource adequacy decisions. Mississippi Commission explains that, when an RTO/ISO approves construction to deliver generation output to remote utilities that have failed to agree to purchase the energy, that RTO/ISO infringes on the state's resource adequacy jurisdiction.[512] Mississippi Commission contends that requiring State A to pay for transmission upgrades to rely on energy generated in State B, despite State A having constructed its own generation facilities, would usurp State A's resource adequacy jurisdiction.[513]

ii. ''Major Questions Doctrine''

202. Some commenters argue that the NOPR proposal would not withstand judicial review under the major questions doctrine.[514]

203. Louisiana Commission claims that the NOPR proposal violates principles of ''agency law'' and the separation of powers doctrine because Congress has not clearly delegated to the Commission the authority to enact far-reaching, nationwide policy changes favoring one form of generation over another.[515] Louisiana Commission

[495] AEE Reply Comments at 23.

[496] Kentucky Commission Chair Chandler Reply Comments at 6.

[497] SREA Reply Comments at 2–3.

[498] New Jersey Commission Reply Comments at 1–2.

[499] *Id.* at 2.

[500] *Id.*

[501] Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2–3; Southern Initial Comments at 21–22.

[502] Southern Initial Comments at 21–22.

[503] Alabama Commission Initial Comments at 7.

[504] Kansas Ratepayer Advocates Reply Comments at 3.

[505] Nevada Commission Initial Comments at 2–3.

[506] NARUC Initial Comments at 29.

[507] Mississippi Commission Initial Comments at 5 (citing Mississippi Commission ANOPR Comments at 2, 17; NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at PP 2, 11–14)).

[508] Nevada Commission Initial Comments at 6.

[509] Ohio Consumers Initial Comments at 26 (citing *New York* v. *FERC,* 535 U.S. at 23–24, 26–28).

[510] SREA Reply Comments at 1–2.

[511] Vistra Initial Comments at 4 & n.6.

[512] Mississippi Commission Initial Comments at 5–6.

[513] *Id.* at 13.

[514] Louisiana Commission Initial Comments at 6, 12–13; Ohio Consumers Reply Comments at 14; SERTP Sponsors Initial Comments at 17–18; Southern Initial Comments at 20–21; Utah Commission Initial Comments at 8–9; Undersigned States Reply Comments at 3–4.

[515] Louisiana Commission Initial Comments at 6.

contends that the NOPR proposals exceed the limits of the FPA, which does not provide clear delegated authority for the Commission to decide types of generating resources. Louisiana Commission argues that the Commission therefore lacks the authority to determine whether the country should undergo a clean energy transition. Drawing parallels between the NOPR proposal and the U.S. Supreme Court's decision in *West Virginia* v. *EPA,* Louisiana Commission avers that the determination of what type of generating resources should be transmitted from where in the United States qualifies as a ''major question'' of public policy that Congress should order.[516]

204. SERTP Sponsors argue that *West Virginia* v. *EPA* reinforces the need for the Commission to exercise restraint in expanding its jurisdiction without a clear Congressional delegation of authority.[517] According to SERTP Sponsors, *West Virginia* v. *EPA* makes clear that the Nation's energy policy and generation mix is a ''major question'' for which the Commission must have direct authorization from Congress to assert jurisdiction.[518] SERTP Sponsors contend that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and thereby effect particular substantive transmission outcomes.[519] Rather, SERTP Sponsors argue that Congress instead expressly and unequivocally reserved generation authority to the states.[520]

205. Southern similarly argues that *West Virginia* v. *EPA* makes clear that the Nation's energy policy and generation mix is a ''major question'' that requires more than a ''merely plausible textual basis'' for a Federal agency to assert jurisdiction.[521] Southern contends that, as applied to the NOPR proposal's ''contemplated foray into [integrated resource planning] and generation/resource matters,'' the Commission does not rely upon a specific and clear grant of congressional authorization but instead relies upon its ''general, gap-filling authorization in FPA Section 206 to regulate a 'practice' affecting a rate or charge for transmission.'' [522] Southern contends that rather than provide clear congressional authorization, Congress instead reserved authority over integrated resource plans and generation to the states.[523]

206. Utah Commission argues that the Commission has no authority to enact any rule for the purpose of influencing the resource generation mix or expanding development of any type of generation. Utah Commission states that the increased development and integration of renewable generation is a ''highly charged political question and a matter of significant political interest about which state legislatures have made very different policy choices.'' As such, Utah Commission argues that, although courts have given the Commission ''some latitude under FPA Section 206,'' the U.S. Supreme Court will not uphold a final order premised upon the Commission's ''claimed authority to prescribe a single, onerous national regime for transmission planning specifically intended to pressure transmission providers to select costly expansions into remote areas for the purpose of realizing [the Commission's] preferred generation mix, a matter specifically reserved to the states.'' [524] Utah Commission explains that the Supreme Court's reasoning in *West Virginia* v. *EPA* is applicable to the Commission. Utah Commission argues that ''imposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of [the Commission's] authority under FPA Section 206.'' [525]

207. Undersigned States argue that ''[n]ational-scale energy grid regulation'' is a ''major question'' because of the ''massive economic consequences'' involved and the implication of a ''unique and complex jurisdictional divide between [s]tate and federal regulatory authority.'' [526] According to Undersigned States, the Commission ''has no statutory authority at all—much less 'clear congressional authorization'—to revamp the energy grid's mix of generation resources writ large.'' [527]

208. Harvard ELI and Policy Integrity disagree with Undersigned States. They argue that Undersigned States ''mischaracterize the NOPR'' because the NOPR would not revamp the energy grid's mix of generation resources. Rather, according to Harvard ELI and Policy Integrity, the NOPR would require utilities to amend their existing regional transmission planning processes in response to changes in the resource mix and demand that are occurring because of factors unrelated to the NOPR.[528]

209. Harvard ELI and Policy Integrity also contend that Undersigned States overlook the major questions doctrine's key requirements. They assert that application of the major questions doctrine does *not* turn on whether a regulation will have significant economic effects or intrudes on areas traditionally regulated by states. Instead, Harvard ELI and Policy Integrity assert that the major questions doctrine is triggered only when an agency's action is both unheralded and transformative.[529]

210. Harvard ELI and Policy Integrity argue that the NOPR is not unheralded. They explain that Order No. 1000 similarly regulated transmission planning and cost allocation in response to concerns about the generation mix, and that the D.C. Circuit upheld Order No. 1000 while rejecting arguments similar to those that Undersigned States make here.[530] Moreover, Harvard ELI and Policy Integrity identify provisions in existing tariffs that are similar to those that the NOPR proposes and point to other antecedents for Commission regulation of regional transmission planning.[531]

211. Likewise, Harvard ELI and Policy Integrity argue that the NOPR does not represent a transformative expansion in the Commission's authority nor a ''fundamental change to the statutory scheme.'' [532] Instead, they assert that the NOPR merely builds on existing regional transmission planning processes to ensure that Commission-jurisdictional rates remain just and reasonable, as the FPA requires.[533]

[516] *Id.* at 12 (citing 597 U.S. 697, 729–30, 735).

[517] SERTP Sponsors Initial Comments at 17 (citing *West Virginia* v. *EPA,* 597 U.S. at 723); *see also* EEI Initial Comments at 8 (urging the Commission to consider the overlap of the Commission's and state commissions' respective jurisdictions).

[518] SERTP Sponsors Initial Comments at 17–18.

[519] *Id.* at 18.

[520] *Id.*

[521] Southern Initial Comments at 20–21 (citing *West Virginia* v. *EPA,* 597 U.S. at 723).

[522] *Id.*

[523] *Id.* at 21.

[524] Utah Commission Initial Comments at 8.

[525] *Id.* at 8–9 (citing *West Virginia* v. *EPA,* 597 U.S. at 729–30).

[526] Undersigned States Reply Comments at 3 (citing *West Virginia* v. *EPA,* 597 U.S. 697; *Ala. Ass'n of Realtors* v. *HHS,* 594 U.S. 758, 764 (2021)).

[527] *Id.* at 4 (quoting *West Virginia* v. *EPA,* 597 U.S. at 723).

[528] Harvard ELI and Policy Integrity Supplemental Comments at 2.

[529] *Id.* at 2–3.

[530] *Id.* at 4 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 48–49; Order No. 1000, 136 FERC ¶ 61,051 at PP 45, 47).

[531] *Id.* at 4–5; *id.* app. A.

[532] *Id.* at 6–7 (quoting *West Virginia* v. *EPA,* 597 U.S. at 723 (internal quotations omitted)).

[533] *Id.*

iii. ''Equal Sovereignty Doctrine''/Cross-Subsidization

212. Some commenters argue that the NOPR's cost allocation proposal impermissibly requires states to subsidize other states' public policies.[534] Undersigned States argue that the NOPR would exceed the Commission's jurisdiction because it violates the Constitution's equal sovereignty doctrine, which provides constitutional equality among the states.[535] According to Undersigned States, the NOPR ''sets up a scheme where one [s]tate can effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation—a core, sovereign [s]tate function,'' which risks ''undue discrimination'' among states.[536] Mississippi Commission argues that unanimous agreement, rather than majority agreement, would be required for any *ex ante* default cost allocation method, as each state has sole jurisdiction within its boundaries.[537]

213. Louisiana Commission asserts that ''*group* state oversight'' is not equivalent to ''state oversight,'' and that the Commission should not adopt a rule that subjects one state's will to majority override. Louisiana Commission further argues that the Commission should not enact rules that would ''impose costs for projects selected under the proposed long-term planning criteria on unwilling states that do not benefit from those projects, even if those states are in the minority.'' Louisiana Commission contends that the Commission should not attempt to override state jurisdiction simply because a majority of states in a region may support imposing costs on unwilling states that do not benefit from transmission projects favored by the majority.[538] Louisiana Commission argues that states should not be required to cede their jurisdiction by engaging in any ''consulting'' committee structure required with respect to Long-Term Regional Transmission Planning,[539] because granting each state one vote in a multi-state body cannot replace the meaningful exercise of state jurisdiction within a state's borders.[540]

214. Conversely, ACEG disputes these claims, which ACEG states are ''incorrect and misconstrue the NOPR.'' [541] ACEG highlights the fact that the NOPR does not include resource preferences in its proposed planning criteria, factors, or benefits, nor does the NOPR exclude consideration of non-renewable resources from transmission planning.[542] ACEG further notes that the NOPR proposes to direct transmission planners to plan the system to ''meet transmission needs driven by changes in the resource mix and demand,'' requiring transmission planners to consider the resource mix as a whole, which necessarily requires considering all types of resources.[543] New Jersey Commission agrees, stating that the Commission did not propose in the NOPR ''to unduly favor, mandate, or subsidize forms of generation,'' but rather ''to ensure that the bulk electricity system maintains reliability and satisfies evolving consumer demands, whether driven by public policy requirements or voluntary goals, at the lowest reasonable cost.'' [544] Moreover, New Jersey Commission argues, allocating the cost of Long-Term Regional Transmission Facilities only to those states with relevant public policy goals ''would allow the remaining states to free ride, and effectively force the states with public policy goals to subsidize the provision of normal electricity service in other states in order to pursue their own policies.'' [545]

i. Other Issues

215. NRECA requests that the Commission clarify that the final order, consistent with the Commission's obligation under FPA section 217(b)(4), ''is intended to facilitate and support 'bottom-up' transmission planning to meet the transmission needs of [load-serving entities] to provide reliable and economical service to consumers.'' [546]

216. Some commenters argue that the final order will not withstand judicial scrutiny if it does not permit regional flexibility.[547] For example, US Chamber of Commerce explains that the interstate power grid includes investor-owned utilities, publicly-owned utilities, and electric cooperatives, which can be members of RTOs/ISOs, power pooling arrangements, joint-ownership agreements, or subject to traditional vertically-integrated structures.[548] According to US Chamber of Commerce, imposing a new regional transmission planning regime on all these various entities would ignore the compromises and benefits that led to the status quo.[549] Relatedly, Southern and SERTP Sponsors argue that the legal viability of the final order will be threatened if the Commission fails to respect the FPA's fundamental jurisdictional roles by not providing states and transmission providers with the opportunity and flexibility to adapt their planning processes.[550]

j. Miscellaneous Concerns

217. MISO seeks clarification from the Commission that the term ''transmission planning region'' has the same meaning as in Order No. 1000, where MISO may comprise a single transmission planning region despite including multiple transmission zones or local balancing authorities.[551]

218. California Municipal Utilities state that transmission planning should not be a vehicle to centralize resource choices, but instead should reflect the choices made by state and local authorities.[552] Similarly, Mississippi Commission argues that Long-Term Regional Transmission Planning should be driven by state-specific concerns and needs and that regional priorities should be subordinated to state priorities.[553] Mississippi Commission asks that the Commission not issue a final order but instead establish proceedings to address specific concerns with certain regional transmission planning processes on a more limited basis.[554] Southern argues that Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions must have the support of affected states, as these facilities stem from resource and load assumptions that are not the result of those states' planning and procurement processes.[555] Southern urges the Commission to maintain the appropriate transmission

[534] Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 29; Mississippi Commission Reply Comments at 3; Ohio Commission Federal Advocate Initial Comments at 4–5; Ohio Consumers Reply Comments at 14.

[535] Undersigned States Reply Comments at 5–6 (citing *Coyle* v. *Smith,* 221 U.S. 559, 567 (1911)).

[536] *Id.* at 6 (citing NOPR, 179 FERC ¶ 61,018, Danly, Comm'r, dissenting, at PP 4–5).

[537] Mississippi Commission Reply Comments at 2–3.

[538] Louisiana Commission Initial Comments at 27–28; Louisiana Commission Reply Comments at 14–16.

[539] Louisiana Commission Initial Comments at 28–29.

[540] Louisiana Commission Reply Comments at 16.

[541] ACEG Reply Comments at 18.

[542] *Id.* at 18–19.

[543] *Id.* at 19.

[544] New Jersey Commission Initial Comments at 3.

[545] *Id.* at 20.

[546] NRECA Initial Comments at 17–21.

[547] SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1–2; Southern Initial Comments at 1; Southern Reply Comments at 3; US Chamber of Commerce Initial Comments at 4.

[548] US Chamber of Commerce Initial Comments at 4.

[549] *Id.*

[550] Southern Initial Comments at 1; Southern Reply Comments at 3; SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1–2.

[551] MISO Initial Comments at 24.

[552] California Municipal Utilities Reply Comments at 2.

[553] Mississippi Commission Initial Comments at 3.

[554] *Id.* at 9.

[555] Southern Initial Comments at 8.

planning and state-driven supply- and demand-side relationships, which Order No. 1000 preserved.[556] SERTP Sponsors argue that the Commission should avoid mandates that could largely result in transmission expansion or infrastructure decisions that lead to investments borne, largely, by retail electricity consumers that lack the consent and support of the state authorities vested with the responsibility to protect those consumers.[557]

219. Several commenters agree with the Commission that any final order should apply to transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions.[558] However, several commenters disagree and argue that the final order, or certain specified requirements in the final order, should apply only to RTO/ISO transmission planning regions.[559] Nevada Commission argues that the RTOs/ISOs ''may be better suited'' than other regions for the transmission planning that the NOPR proposes.[560] Utah Division of Public Utilities stresses the need for regional flexibility, noting that transmission providers located outside of RTOs/ISOs already coordinate on transmission planning with many non-Commission-jurisdictional entities.[561]

220. SEIA rebuts the claims of Southern and Louisiana, Utah, Mississippi, and Alabama Commissions that state planning processes already interact well with transmission planning and support customers' transmission needs.[562] SEIA and SREA assert that non-RTO/ISO transmission planning regions do not engage in sufficient or transparent transmission planning.[563] Specifically, SEIA states, the transmission planning processes in non-RTO/ISO regions are rife with issues, including the use of inconsistent and inaccurate data and an exclusionary and insufficiently transparent process.[564] Further, SEIA states that the end result of an integrated resource planning process may be based on inconsistent and inaccurate data,[565] the process is ''sometimes disjointed,''[566] and the process is a voluntary process in which the planning authority must accept, and not verify, the information provided.[567]

221. SREA rebuts Southern's contention that Southern's transmission planning processes are adequate, noting that Southern itself has presented testimony to the Georgia Commission conceding that it is unable to perform more robust transmission planning due to limitations in its software and models.[568] SREA argues that throughout the Southeast, transmission planning is not a priority and that integrated resource planning is not a substitute for robust transmission planning.[569] SREA explains that the NOPR borrows many of the qualities of integrated resource planning and applies them to transmission planning, including scenario-based evaluation and use of 20-year planning horizons, and that many states have integrated resource planning rules and guidelines that recognize the value of long-term planning.[570]

222. EPSA states that the Commission should focus not on socializing transmission costs but on reducing transaction costs, accelerating lagging processes, and adopting market-based solutions like open seasons.[571]

223. GridLab states that there is evidence to suggest that changes in resource mix, demand, and weather will lead to significant changes in the value of regional transmission facilities in the 2030s, though GridLab asserts that these changes may increase or decrease the value of regional transmission facilities. Accordingly, GridLab recommends that the Commission and stakeholders resist evaluating the success of this rulemaking based on arbitrary metrics related to each transmission provider's expansion of regional transmission facilities.[572]

3. Commission Determination

a. Participation in Long-Term Regional Transmission Planning

224. We adopt the NOPR proposal to require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those 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 Long-Term Transmission Needs.[573] We also adopt the NOPR proposal to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[574] In developing their compliance filings, transmission providers and stakeholders should review the requirements set forth in Order No. 890 and Order No. 1000, and the Commission's orders on compliance filings submitted by transmission providers, for guidance as to what each of these transmission planning principles requires. For example, as a starting point, a transmission provider should review the orders addressing its own Order Nos. 890 and 1000 compliance filings and the compliance filings for transmission providers in its transmission planning region.

225. We also adopt specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning. Specifically, and as discussed further below, we require transmission providers in each transmission planning region[575] to: (1) identify Long-Term

[556] *Id.* at 12.

[557] SERTP Sponsors Initial Comments at 6–7.

[558] *See, e.g.,* AEE Reply Comments at 11; MISO Reply Comments at 3; PIOs Reply Comments at 2–3; SEIA Reply Comments at 5; SREA Initial Comments at 47; TAPS Initial Comments at 70.

[559] *See, e.g.,* Mississippi Commission Initial Comments at 16; Utah Division of Public Utilities Reply Comments at 1–2.

[560] Nevada Commission Initial Comments at 2–4.

[561] Utah Division of Public Utilities Reply Comments at 1–2.

[562] SEIA Reply Comments at 5.

[563] *Id.;* SREA Reply Comments at 15–17.

[564] SEIA Reply Comments at 5–6.

[565] *Id.* at 5 (citing Western PIOs Initial Comments at 10).

[566] *Id.* (citing PacifiCorp and NV Energy Initial Comments at 10).

[567] *Id.* (citing PacifiCorp and NV Energy Initial Comments at 13; Western PIOs Initial Comments at 11).

[568] SREA Reply Comments at 7 (citing SREA Initial Comments, attach. B (Testimony of Georgia Power Witness Robinson) at 282–283).

[569] *Id.* at 5.

[570] *Id.*

[571] EPSA Initial Comments at 7–8.

[572] GridLab Initial Comments at 9–10.

[573] We note that, while we have modified this definition of Long-Term Regional Transmission Planning from the NOPR proposal, the modified definition does not substantively change the steps involved in Long-Term Regional Transmission Planning from those proposed in the NOPR. Rather, the revised definition merely clariies the steps that transmission providers must take in conducting Long-Term Regional Transmission Planning.

[574] Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 151. We do not address these principles in detail here.

[575] In response to MISO's request, MISO Initial Comments at 24, we clarify that this final order does not alter the meaning of ''transmission planning region'' as used in Order No. 1000. A transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. Order No. 1000–A, 139 FERC ¶ 61,132 at P 272; Order No. 1000, 136 FERC ¶ 61,051 at P 160.

Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios [576] that satisfy the requirements set forth in this final order; (2) use and measure, at a minimum, a set of seven required benefits [577] to evaluate Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of each transmission facility; and (3) evaluate Long-Term Regional Transmission Facilities to determine whether they are more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs and use selection criteria (in collaboration with states and other stakeholders) that provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities.

226. These requirements together establish a long-term, forward-looking, and more comprehensive approach to regional transmission planning, which will ensure that transmission providers identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs. Long-Term Regional Transmission Planning, as set forth in this final order, requires regional transmission planning based on a multitude of drivers of Long-Term Transmission Needs and provides the opportunity for transmission providers to meet those needs by selecting more efficient or cost-effective Long-Term Regional Transmission Facilities.

227. In considering the comments received on this proposal, we strike a careful balance. On the one hand, we believe that there is an inherent risk in transmission providers waiting for the near-term certainty that some commenters appear to believe is necessary [578] before planning to address transmission needs. As explained in the Overall Need for Reform section above, doing so may result in transmission providers relying on relatively inefficient and less cost-effective piecemeal transmission solutions to address these needs shortly before they manifest, to the detriment of customers. On the other hand, we acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs and that this uncertainty means that forward-looking regional transmission planning entails certain risks, including the risk that transmission needs may change over time. In this final order, we balance these risks, requiring planning to meet Long-Term Transmission Needs, while imposing requirements on how Long-Term Regional Transmission Planning is conducted, as discussed further herein, to mitigate uncertainty. To adequately prepare for the future, transmission providers need to make decisions in the present that are grounded in a thorough, informed analysis of the factors that drive Long-Term Transmission Needs.

228. As discussed in the Overall Need for Reform section, these factors are together driving rapid changes in the Long-Term Transmission Needs that transmission providers must plan to meet to continue to provide an affordable, reliable supply of electricity to customers, but neither transmission infrastructure nor regional transmission planning processes are keeping pace. Consequently, the Commission's existing regional transmission planning requirements are no longer just and reasonable, as they increasingly result in transmission investment decisions occurring outside of regional transmission planning processes and instead through generator interconnection processes and local transmission planning processes that typically plan to meet discrete, nearer-term transmission needs. In addition, the record demonstrates that transmission providers have made substantial investments in in-kind replacement transmission facilities, which generally are not identified through more long-term, forward-looking, or comprehensive transmission planning. This final order aims to ensure that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, helping to ensure just and reasonable rates.

229. We disagree with arguments that the Commission should not require Long-Term Regional Transmission Planning because, certain commenters claim, doing so will introduce excessive uncertainty into regional transmission planning, transmission providers will make forecasting errors, or the final order will result in regional transmission planning that is speculative.[579] To the contrary, we believe that the reforms adopted in this final order account for and seek to reduce the inherent uncertainty in forward-looking regional transmission planning, while ensuring that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, thus helping to ensure just and reasonable rates.[580] In fact, by requiring transmission providers to use Long-Term Scenarios in Long-Term Regional Transmission Planning, this final order provides transmission providers with a critical tool for managing uncertainty, facilitating regional transmission planning that accounts for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate Long-Term Regional Transmission Facilities in certain circumstances, which will provide transmission providers with yet another such tool.

230. Moreover, notwithstanding allegations to the contrary, we believe that Long-Term Regional Transmission Planning is a logical and reasonable extension of current regional transmission planning processes, which also manage uncertainty and plan for future regional transmission needs. The key difference, which we address through this final order, is that these existing regional transmission planning processes are conducted in a manner that is not sufficiently long-term, forward-looking, or comprehensive such that transmission providers are not identifying Long-Term Transmission Needs. As a result, transmission providers are failing to identify or evaluate regional transmission facilities that would more efficiently or cost-effectively address those Long-Term Transmission Needs, and consequently,

[576] The requirements related to Long-Term Scenarios are discussed below.

[577] As discussed further below in the Evaluation of the Benefits of Regional Transmission Facilities section, these seven benefits are: (1) Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement; (2) Benefit 2(a), Reduced Loss of Load Probability, or Benefit 2(b), Reduced Planning Reserve Margin; (3) Benefit 3, Production Cost Savings; (4) Benefit 4, Reduced Transmission Energy Losses; (5) Benefit 5, Reduced Congestion Due to Transmission Outages; (6) Mitigation of Extreme Weather Events and Unexpected System Conditions; and (7) Capacity Cost Benefits from Reduced Peak Energy Losses.

[578] *See, e.g.,* NRG Initial Comments at 8 (arguing that there are unliekly to be any ''no regrets'' options).

[579] Louisiana Commission Initial Comments at 4–5; NRG Initial Comments at 3–4; Ohio Consumers Initial Comments at 5.

[580] *See* Policy Integrity Initial Comments at 6 (arguing that future uncertainty requires scenario planning).

are missing the opportunity to select such regional transmission facilities. Our reforms in this final order remedy these deficiencies.

231. Further, we believe that Long-Term Regional Transmission Planning as set forth in this final order provides adequate safeguards against excessive transmission development in response to speculative transmission needs. For example, this final order requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios based upon best available data, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and requires transmission providers to update their assumptions periodically, as discussed further below.[581] In developing these Long-Term Scenarios, transmission providers are required to treat more certain drivers of Long-Term Transmission Needs differently than less certain drivers, and must provide opportunities for stakeholder engagement. Further, the final order grants substantial flexibility to transmission providers to develop an evaluation process and selection criteria that will provide them with the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities. Consistent with the existing Order No. 1000 regional transmission planning processes, the final order does not require transmission providers to select any regional transmission facilities as part of Long-Term Regional Transmission Planning. Finally, we require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities in certain circumstances, as discussed further below in the Reevaluation section.

232. The regional transmission planning and cost allocation requirements in this final order, like those of Order Nos. 890 and 1000, are focused on the transmission planning *process,* and do not require any substantive outcomes from this process.[582] We disagree with certain commenters' assertions that this final order favors, promotes, or subsidizes particular types of generation resources over others, or otherwise engages in generation planning.[583] Instead, this final order requires transmission providers to participate in Long-Term Regional Transmission Planning through their regional transmission planning process that identifies Long-Term Transmission Needs, evaluates the benefits of Long-Term Regional Transmission Facilities to meet those needs, and provides the opportunity for transmission providers to select Long-Term Regional Transmission Facilities that are more efficient or cost-effective transmission solutions to those needs. We reiterate that, as discussed below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, any selected Long-Term Regional Transmission Facilities must satisfy transmission provider-developed selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities, which ensures that the costs of such transmission facilities are outweighed by the benefits they deliver to customers.

233. We disagree with commenters that argue that the factors giving rise to Long-Term Transmission Needs, such as state laws dictating specific generation resource mixes, are irreconcilable with effective transmission planning.[584] These changes are occurring independent of any action that we take in this final order, and they are being driven by a wide variety of factors. This final order provides transmission providers with the tools that they need to respond to these factors, requiring that they conduct Long-Term Regional Transmission Planning to identify, evaluate, and select Long-Term Regional Transmission Facilities that are more efficient or cost-effective regional transmission solutions to the Long-Term Transmission Needs that these factors drive.

234. We disagree with Louisiana Commission and former Kansas Commission Chairman Keen's claims that Long-Term Regional Transmission Planning will threaten the reliability of the transmission system. We acknowledge that reliability needs are evolving; for example, the increasing frequency and severity of high-impact extreme weather events threatens grid reliability. We believe that Long-Term Regional Transmission Planning—in addition to existing Order No. 1000 regional transmission planning and cost allocation requirements—is needed to support the reliable operation of transmission systems, given these changes. As the Commission and the North American Electric Reliability Corporation have noted, the transmission system may not be adequately prepared for extreme weather events and the increasing frequency of these events must be planned for to ensure system reliability.[585] We thus view our action in this final order as complementary to other steps that the Commission has taken in recent years to bolster system reliability.[586]

235. Further, we disagree with the contention of Louisiana Commission and Vistra that Long-Term Regional Transmission Planning will distort the efficient functioning of Commission-jurisdictional wholesale markets by subsidizing uneconomic generation or by distorting price signals. As discussed further below, we require transmission providers, as part of Long-Term Regional Transmission Planning, to assess the costs and measure the benefits of regional transmission facilities that address Long-Term Transmission Needs and to develop evaluation processes and selection criteria that provide the opportunity to select those transmission facilities as more efficient or cost-effective regional transmission solutions to those Needs. While the addition of any new transmission facility necessarily affects Commission-jurisdictional wholesale markets, the requirements set forth in this final order ensure that transmission providers will have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities that provide value to transmission customers and support the efficient functioning of wholesale markets by addressing Long-Term Transmission Needs.

[581] *See* New Jersey Commission Initial Comments at 10–11.

[582] *See, e.g.,* Order No. 1000, 136 FERC ¶ 61,051 at P 12.

[583] Alabama Commission Initial Comments at 7–8; Louisiana Commission Initial Comments at 12, 19–21; Potomac Economics Initial Comments at 3–4; Utah Division of Public Utilities Initial Comments at 2; Vistra Initial Comments at 11.

[584] *See* ELCON Initial Comments at 9 (''ELCON has always believed that planning for disparate state energy priorities is at odds with market-driven, efficient, and cost-effective transmission planning.'').

[585] FERC, North American Electric Reliability Corporation, *Winter Storm Elliot Report: Inquiry into Bulk-Power System Operations During December 2022* (Nov. 2023), *https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022;* FERC, North American Electric Reliability Corporation, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021), *https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.*

[586] *See, e.g., Transmission Sys. Planning Performance Requirements for Extreme Weather,* Order No. 896, 88 FR 41262 (June 23, 2023), 183 FERC ¶ 61,191 (2023); *One-Time Info. Reports on Extreme Weather Vulnerability Assessments,* Order No. 897, 88 FR 41447 (June 27, 2023), 183 FERC ¶ 61,192 (2023).

236. We also disagree with Vistra's contention that Long-Term Regional Transmission Planning somehow will assign all, or a disproportionately high share, of interconnection-related network upgrade costs to load or undermine the incentives for generation developers to site new generation resources in ways that minimize transmission system upgrade costs. Rather, because transmission providers will now engage in Long-Term Regional Transmission Planning to identify, evaluate, and select more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs, Long-Term Regional Transmission Facilities will be planned in a more efficient and cost-effective manner than if transmission facilities meeting a narrower set of transmission needs were left to be identified through the generator interconnection process. Indeed, numerous commenters explain that the piecemeal expansion of the transmission system is highly inefficient and results in higher costs for transmission customers,[587] in part because the costs of interconnection-related network upgrades ultimately are passed on to consumers.

237. We strike another careful balance in this final order. On the one hand, we recognize transmission providers' need for sufficient flexibility to implement Long-Term Regional Transmission Planning in their transmission planning regions to reflect regional differences, such as different market structures.[588] On the other hand, we must ensure that transmission providers' regional transmission planning processes result in just and reasonable rates, which, as discussed above in the Overall Need for Reform section, necessitates that they plan on a sufficiently long-term, forward-looking, and comprehensive basis such that transmission providers are identifying, evaluating, and selecting more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs. We believe that the balance struck in the final order will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential and, thus, we reject requests for flexibility that exceeds that provided in this final order.

238. In particular, we reject requests that, instead of requiring transmission providers to implement Long-Term Regional Transmission Planning in accordance with the requirements adopted in this final order, we set forth principles and objectives articulating our concerns with existing regional transmission planning processes and give transmission providers the flexibility to propose revisions to their processes to address those concerns.[589] Having found existing regional transmission planning and cost allocation requirements to be unjust and unreasonable, we have an obligation under FPA section 206 to adopt reforms that remedy the deficiencies identified in this final order. We also believe that such an approach would fail to adequately address the deficiencies described above in the Overall Need for Reform section, namely that transmission providers are not currently required to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We further believe that establishing requirements rather than principles will ensure a sufficiently robust process for Long-Term Regional Transmission Planning while providing sufficient clarity about that process to avert conflict among stakeholders, as noted by AEP.[590]

239. We also disagree with commenters that argue that this final order should apply to only RTO/ISO transmission planning regions. The Commission's existing regional transmission planning requirements, which, as described above in the Overall Need for Reform section, we find to be deficient, apply in RTO/ISO and non-RTO/ISO transmission planning regions alike; without the Long-Term Regional Transmission Planning Requirements adopted herein, transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions will continue to be at risk of undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, while we acknowledge differences between RTO/ISO and non-RTO/ISO transmission planning regions, we find that transmission providers in all transmission planning regions must implement Long-Term Regional Transmission Planning as required in this final order to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. Additionally, we note that many of the requirements established in this final order provide for regional flexibility, including, but not limited to, the requirements to develop Long-Term Scenarios, determine which factors in each required category of factors do not affect Long-Term Transmission Needs and need not be considered, develop methods to measure the benefits of Long-Term Regional Transmission Facilities, design an evaluation process and selection criteria, and establish a Long-Term Regional Transmission Cost Allocation Method.

240. We acknowledge that certain transmission planning regions already conduct some regional transmission planning on a relatively forward-looking, proactive basis. We do not intend to undermine progress made in these transmission planning regions, and our goal is to set a floor, not a ceiling. We decline to prejudge whether any existing regional transmission planning process meets the requirements set forth in this final order and accordingly reject requests that we do so.[591] We note that, if a transmission provider believes that it participates in a regional transmission planning process that fulfills the requirements adopted in this final order, it may describe in its compliance filing how its process meets these requirements.

241. We expect Long-Term Regional Transmission Planning to enhance the existing regional transmission planning and cost allocation processes required by Order No. 1000. Except as set forth in this final order, we do not require that any transmission provider replace or otherwise make changes to its existing Order No. 1000-compliant regional transmission planning processes that plan for reliability or economic transmission needs, or the associated Order No. 1000-compliant regional cost allocation method(s). Transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.

[587] *See, e.g.,* NYISO Initial Comments at 30; PIOs Initial Comments at 9–10.

[588] The Commission also recognized the need for sufficient flexibility in regional transmission planning to reflect regional differences in Order No. 1000. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 61.

[589] ISO–NE Initial Comments at 20; ISO RTO Council Initial Comments at 4–5, 8–9; MISO Initial Comments at 22–23.

[590] AEP Reply Comments at 2–4.

[591] *See, e.g.,* Ameren Initial Comments at 8.

242. We also do not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process. Instead, we clarify that we will deem transmission providers to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final order. As discussed below, we require transmission providers to incorporate a variety of factors into the development of Long-Term Scenarios, which include, among others, certain Federal, state, and local laws and regulations. Therefore, we find that transmission providers that implement Long-Term Regional Transmission Planning and satisfy the requirements set forth in this final order will comply with the requirement in Order No. 1000 to participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.

243. We understand—and acknowledge comments submitted in this proceeding explaining—that transmission providers in some transmission planning regions have developed processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes that they wish to retain.[592] In their filings made to comply with this final order, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements. Transmission providers must nevertheless comply with the Long-Term Regional Transmission Planning requirements set forth in this final order, such that continued use of existing regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements will not supplant transmission providers' obligation to comply with this final order. In their filing to comply with this final order, transmission providers that wish to continue to use some or all of their existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final order.

244. Similarly, we allow transmission providers to propose a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs, as well as Long-Term Transmission Needs, as outlined in this final order, through a combined process. Transmission providers proposing to address all of these transmission needs in a single regional transmission planning process must demonstrate that the unified regional transmission planning process continues to comply with Order No. 1000, as well as with the Long-Term Regional Transmission Planning requirements set forth in this final order, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order No. 1000 and this final order. However, in the case that the requirements of Order No. 1000 and this final order conflict, the requirements of this final order prevail, and transmission providers must demonstrate that their proposed regional transmission planning process is consistent with or superior to the applicable requirements in this final order.

245. We reject requests to require transmission providers to simultaneously plan for all such transmission needs through a single regional transmission planning process, however.[593] We recognize that such a combined process has potential benefits and do not prohibit such an approach, but at this time we believe that the benefits of requiring such a combined process on a generic basis may be outweighed by the difficulty of transitioning to such a process from existing regional transmission planning processes. Therefore, we do not require in this final order that transmission providers plan for all reliability and economic transmission needs and Long-Term Transmission Needs through a single regional transmission planning process. Further, we believe that Long-Term Regional Transmission Planning, as set forth in this final order, meets many of the same objectives as would such a combined regional transmission planning process because, by identifying Long-Term Transmission Needs and considering a broad set of benefits when evaluating Long-Term Regional Transmission Facilities, the existing regional transmission planning processes for economic and reliability needs may ultimately come to address only residual needs not already addressed through Long-Term Regional Transmission Planning.

246. With respect to the request by PIOs to mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process,[594] we decline to adopt this proposal. The record is inadequate to assess the impact that such a requirement would have on existing Order No. 1000 regional transmission planning processes, and whether this proposal would work across the differing transmission planning processes in each transmission planning region. With respect to the proposals by Clean Energy Buyers, Cypress Creek, and Policy Integrity,[595] these proposals were not among the proposals included in the NOPR and are beyond the scope of this proceeding, and therefore we decline to adopt them.

247. We also reject requests to incorporate local transmission planning into Long-Term Regional Transmission Planning specifically or regional transmission planning more generally,[596] as well as requests to require transmission providers to evaluate and approve local transmission facilities in regional transmission planning.[597] This final order sets forth requirements that will enhance the transparency of local transmission planning and examine opportunities for right-sizing in-kind replacements of existing transmission facilities, including local transmission facilities, but the Commission in the NOPR did not propose other changes to local transmission planning processes and therefore these requests are beyond the scope of this final order.

248. As discussed in detail below, we require transmission providers to satisfy specific requirements in implementing Long-Term Regional Transmission Planning, including requirements to: (1) use a transmission planning horizon of no less than 20 years into the future in developing Long-Term Scenarios; (2) reassess and revise those scenarios at least once every five years; (3) incorporate into the Long-Term Scenarios a set of Commission-identified categories of factors that give rise to Long-Term Transmission Needs;

[592] CAISO Reply Comments at 17–18; New York Transco Initial Comments at 5.

[593] *See, e.g.,* ACEG Initial Comments at 30–31.

[594] PIOs Initial Comments at 44–46.

[595] Clean Energy Buyers Initial Comments at 9–10; Cypress Creek Reply Comments at 10–12; Policy Integrity Supplemental Comments at 3.

[596] AEE Initial Comments at 3, 38.

[597] OMS Initial Comments at 16–17.

(4) develop a plausible and diverse set of at least three Long-Term Scenarios; (5) perform sensitivity analyses of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area; and (6) use ''best available data'' in developing Long-Term Scenarios.

249. Before turning to these topics, however, we address two preliminary matters: the definition of Long-Term Regional Transmission Facility; and our jurisdiction to adopt these reforms.

b. Definition of Long-Term Regional Transmission Facility

250. We modify the NOPR proposal and define Long-Term Regional Transmission Facility for purposes of this final order as a regional transmission facility, as defined in Order No. 1000, that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.[598] In so doing, we clarify that some Long-Term Regional Transmission Facilities may be selected in a regional transmission plan for purposes of cost allocation, while others may be considered for selection but not be selected.

251. This modification also clarifies that Long-Term Regional Transmission Facilities are a subset of regional transmission facilities as defined in Order No. 1000. Further, consistent with Order No. 1000,[599] a selected Long-Term Regional Transmission Facility is a regional transmission facility that has been selected pursuant to a Commission-approved Long-Term Regional Transmission Planning process in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective solution to Long-Term Transmission Needs.

252. We disagree with PJM that Order No. 1000's requirements related to regional transmission planning processes addressing transmission needs driven by reliability concerns or economic considerations will be unclear given the definition of Long-Term Regional Transmission Facility, and we find unpersuasive PJM's contention that Long-Term Regional Transmission Planning will inadvertently cause the re-litigation of aspects of those existing processes. If a regional transmission facility is selected in an existing Order No. 1000 regional transmission planning process, the rules of, as well as the regional cost allocation method for, that existing process apply to the selected regional transmission facility. If a Long-Term Regional Transmission Facility is selected in Long-Term Regional Transmission Planning, then the rules of, and the Long-Term Regional Cost Allocation Method for, Long-Term Regional Transmission Planning apply to that Long-Term Regional Transmission Facility.

c. Legal Authority To Adopt Reforms for Long-Term Regional Transmission Planning

253. We reaffirm our conclusion in the NOPR that we are acting within the Commission's legal authority under FPA section 206 by requiring transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning. The FPA grants the Commission authority over the transmission of electric energy in interstate commerce, which includes transmission on the interconnected national grids.[600] FPA section 205 requires that the rates charged by any public utility in connection with such transmission—as well as the rules and regulations affecting such rates—be just and reasonable, and further requires that public utilities file with the Commission the practices affecting such rates.[601] Under FPA section 206, when the Commission determines that any rate or any practice affecting such rate is unjust, unreasonable, or unduly discriminatory or preferential—as we find above with respect to transmission planning practices—the Commission must determine the just and reasonable rate or practice to be followed.[602] Transmission planning and cost allocation processes are practices affecting the rates charged by public utilities in connection with the Commission-jurisdictional transmission of electric energy in interstate commerce.[603] No commenter has claimed otherwise.

254. Despite this, a number of commenters claim that the specific transmission planning requirements we adopt in this final order infringe on the authority reserved to the states by FPA section 201 or are otherwise barred by certain prudential or constitutional principles. As a threshold matter, we believe that commenters' concerns with respect to our jurisdiction or authority to adopt this final order mainly arise from factual misunderstandings or mischaracterizations about what Long-Term Regional Transmission Planning will and will not require transmission providers to do. As explained above, this final order requires transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning and to conduct Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final order. Transmission providers are required to identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities that meet such needs, measure the benefits of these Long-Term Regional Transmission Facilities, and evaluate these Long-Term Regional Transmission Facilities for potential selection. As such, this final order does not regulate, aim at, or otherwise attempt to influence integrated resource planning, the generation mix, decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states under FPA section 201.

255. As discussed in the Introduction and Background section above, the requirements of this final order build upon more than a quarter century of significant actions taken by the Commission on transmission planning and cost allocation, beginning with the Commission's initial open access reforms in Order No. 888. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT based on more than 10 years of experience since the issuance of Order No. 888. Most recently, in 2011, the Commission issued Order No. 1000, which required transmission providers to develop a regional transmission plan after evaluating whether regional transmission facilities may be more efficient or cost-effective than transmission facilities identified in local transmission planning processes and to consider transmission needs driven by Public Policy Requirements. These practices serve as the foundation for regional transmission planning, and this final order leaves them in place.

256. As described above, however, we have identified specific gaps in the Order No. 1000 framework—namely, that regional transmission planning practices do not perform a sufficiently

[598] In the NOPR, the Commission proposed to define a Long-Term Regional Transmission Facility as a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. NOPR, 179 FERC ¶ 61,028 at P 252 n.398.

[599] Order No. 1000, 136 FERC ¶ 61,051 at P 63.

[600] *New York* v. *FERC,* 535 U.S. at 16–17 (citing 16 U.S.C. 824(b)).

[601] 16 U.S.C. 824d.

[602] 16 U.S.C. 824e.

[603] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55–59; *accord Emera Me.* v. *FERC,* 854 F.3d at 673–74.

long-term assessment of transmission needs, adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs, or consider the broader set of benefits of regional transmission facilities. In this final order, we direct reforms to close these gaps without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal in the face of similar objections to those raised here.[604]

257. Critically, as in Order No. 1000, our focus continues to be on ensuring that Commission-jurisdictional regional transmission planning processes are just and reasonable and that, as a result of improvements to the regional transmission planning and cost allocation processes, Commission-jurisdictional rates remain just and reasonable.[605] And, as in Order No. 1000, while the improvements to the regional transmission planning and cost allocation processes will ensure that potentially more efficient or cost-effective regional transmission facilities are evaluated for potential selection and have a cost allocation method available if they are selected, this order does not mandate development of any particular transmission facility.

258. Consistent with the regional transmission planning and cost allocation reforms adopted in Order No. 1000, and in response to commenters arguing otherwise,[606] we affirm that this final order does not authorize or require any entity to adopt a particular siting plan for Long-Term Regional Transmission Facilities that transmission providers select; or to forego state-jurisdictional siting proceedings where they are necessary; or to begin construction on such Long-Term Regional Transmission Facilities. Even where transmission providers select a Long-Term Regional Transmission Facility, the relevant transmission developer typically must secure a variety of other permits and authorizations before beginning to construct the facility, including those that are subject to state jurisdiction. Nothing in this final order changes otherwise applicable siting laws or requirements.

259. Similarly, this final order does not change existing mechanisms for cost-recovery through retail rates; authorize or require states or state commissions to change the laws or regulations that govern the conduct of integrated resource planning or request for proposal processes; authorize or require transmission providers or transmission developers to bypass any applicable state-regulated integrated resource planning or request for proposal processes; or authorize or require states or public utilities to adopt a different mix of generation resources than would otherwise be the case. Comments suggesting otherwise do not accurately represent the Commission's proposed requirements in the NOPR or the requirements adopted in this final order,[607] which seeks to ensure that transmission providers plan for Long-Term Transmission Needs, however those needs arise.[608]

260. We disagree with Southern and SERTP Sponsors' characterization of Long-Term Regional Transmission Planning as a Commission-regulated integrated resource planning/request for proposal process.[609] Similarly, comments that suggest that this final order intends to ''revamp the energy grid's mix of generation resources writ large'' [610] are incorrect. We understand these comments to argue that the Commission seeks reforms to regional transmission planning and cost allocation processes so that it can direct or influence investments toward particular resources, as would an entity engaged in integrated resource planning. In this final order, the Commission neither aims to influence the resource mix, nor, as a practical matter, could the final order achieve such an outcome.

261. Instead, the final order merely requires transmission providers to account for observable changes affecting the transmission system. The final order neither directs those changes, nor does it require any entity, including a state, to approve changes to any subject within its jurisdiction. As with Order Nos. 890 and 1000, which built on the Commission's open access reforms in Order No. 888, this final order *responds* to changes in the electric industry that have arisen in the years since the Commission's last regulatory action related to transmission planning. As discussed above in the Overall Need for Reform section, this final order responds to evolving reliability concerns, including the increasing frequency of high-impact extreme weather events; changes in electricity demand, including significant load growth that is projected to increase in coming years; changes in supply, including Federal, federally-recognized Tribal, state, and local laws and policies that affect the future resource mix; changes in the economics of generation, transmission, and storage technologies; corporate, governmental, and utility commitments to rely on certain generation resources; and other factors as discussed in this final order.

262. We emphasize that these changes, which are affecting and will continue to drive transmission needs, are not within the Commission's control and, in many cases, are beyond the Commission's jurisdiction. We do not aim to influence these drivers of transmission needs through the requirements in this final order.[611] However, the Commission has an obligation under the FPA to ensure that Commission-jurisdictional transmission rates remain just and reasonable, and we affirm—consistent with the Commission's actions in Order Nos. 890 and 1000—that the Commission has the requisite authority to account for the effects of these changes driving transmission needs in Commission-jurisdictional transmission planning processes.[612]

263. We also emphasize, and no commenter contests, that this final order directly regulates transmission planning

[604] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55–64 (rejecting arguments that the requirement to engage in regional transmission planning, as prescribed in Order No. 1000, exceeded the Commission's jurisdiction under FPA section 206, interfered with traditional state authority reserved under FPA section 201, or improperly interpreted and applied FPA section 202(a)).

[605] *See id.* at 63–64 (affirming that the Commission was acting within its jurisdiction because its planning mandate ''relates wholly to electricity transmission, as opposed to electricity sales'' and ''is directed at ensuring the proper functioning of the interconnected grid spanning state lines'').

[606] Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2–3; Southern Initial Comments at 3–4, 7, 15–17; Southern Reply Comments at 6–7.

[607] Alabama Commission Initial Comments at 3–4, 7–9; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8–10, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2); Nevada Commission Initial Comments at 2–3; SERTP Sponsors Initial Comments at 5, 16, 17 n.20, 19–20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–4, 7–8, 12–13, 15–17, 23–24; Southern Reply Comments at 3, 6–7; Undersigned States Reply Comments at 2, 4–5, 8; Utah Commission Initial Comments at 7–9.

[608] New Jersey Commission Reply Comments at 1–2.

[609] SERTP Sponsors Initial Comments at 16–17; Southern Initial Comments at 3–4, 7, 15–17.

[610] Undersigned States Reply Comments at 4; *see also* Louisiana Commission Initial Comments at 6, 12–13 (arguing that the FPA does not allow the Commission to ''enact[ ] sweeping energy policy changes that would have far-reaching, nation-wide effects'' or to favor one form of generation over another).

[611] *See EPSA,* 577 U.S. 260 at 282 (citing *Oneok, Inc.* v. *Learjet, Inc.,* 575 U.S. 373, 385 (2015)).

[612] *Cf. EPSA,* 577 U.S. at 281–82 (''When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, 824(b) imposes no bar.'').

and cost allocation processes, which are practices that affect the rates for the transmission of electric energy in interstate commerce. Importantly, it directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201. Moreover, in doing so, this final order is not aiming to *indirectly* regulate any matter reserved to the states by FPA section 201. Instead, our aim here is to improve on the Commission's existing transmission planning and cost allocation processes *for the express purpose* of addressing identified deficiencies with those processes.

264. As the U.S. Supreme Court has recognized, it is true that almost any action that the Commission takes with respect to regulating the practices affecting the rates for the transmission of or the wholesale sale of electric energy in interstate commerce will have ''*some* effect, in either the short or long term'' on matters reserved to the states' jurisdiction.[613] But those effects, inevitable as they may be, are ''of no legal consequence'' to determining whether this final order infringes on the states' authority under FPA section 201.[614] Instead, such effects are a ''fact of economic life'' for the electric industry, given Congress's decision in the FPA to divide jurisdiction over the industry, including both generation and transmission, into spheres of Commission and state jurisdiction that are not ''hermetically sealed'' from one another.[615] Accordingly, Commission regulation of Commission-jurisdictional practices affecting transmission may ''have natural consequences'' for generation.[616] But, even where that happens, that does not defeat Federal jurisdiction.

265. Rather, as in *EPSA,* what matters is that this final order aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA. As in Order Nos. 890[617] and 1000,[618] this final order aims to improve Commission-regulated transmission planning *processes,* in this instance by ensuring that they are sufficiently long-term, forward-looking, and comprehensive such that they are capable of identifying and meeting Long-Term Transmission Needs.[619] Thus, this final order ensures just and reasonable Commission-jurisdictional rates and practices by ensuring that transmission providers have adequate processes to identify Long-Term Transmission Needs and to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address those needs.

266. Moreover, as in *EPSA,* what also matters is that ''every aspect of the [final order] happens exclusively'' as part of a process that is subject to the Commission's jurisdiction and governs exclusively how those processes work.[620] In aiming to improve transmission planning processes, this final order does not require that transmission providers achieve any particular substantive *outcome* of those processes, including either the selection or construction of any specific transmission facilities. The final order patently does not aim to alter states' or the Nation's generation mix or otherwise regulate matters that are within state jurisdiction. Indeed, to the contrary, our rationale in this final order is ''all about, and only about, improving'' the relevant matters under the Commission's jurisdiction.[621] Nor is it clear how, under commenters' theory, the final order could be argued to regulate matters under states' jurisdiction, given that the final order does not require investment in any particular transmission facilities, and could not, even indirectly, ensure investments in any particular set of generating facilities that may rely on such transmission facilities.

267. Despite some commenters' claims,[622] nothing in this final order requires states to subsidize other states' public policies and, indeed, this final order requires, consistent with long-established Commission and court precedent, that transmission customers within a transmission planning region need only pay costs that are ''roughly commensurate'' with the benefits that transmission providers estimate they will receive from a regional transmission facility.[623] Thus, the final order ensures that transmission customers nationwide are not required to pay for Long-Term Regional Transmission Facilities from which they do not benefit.

268. The reforms in the final order require greater transparency regarding the benefits that would result from the development of Long-Term Regional Transmission Facilities, but these reforms also continue to allow flexibility, as under Order No. 1000, for the transmission providers in each transmission planning region to determine the appropriate method for allocating to transmission customers the costs of any selected Long-Term Regional Transmission Facility. Rather than force transmission providers to adopt a particular cost allocation method that would necessarily result in customers in one state subsidizing the costs of customers in another state, as these commenters allege, the final order affords significant new opportunities for Relevant State Entities to inform the evaluation process, selection criteria, and cost allocation method adopted by the transmission providers in a transmission planning region. We believe that the requirements for greater transparency regarding the benefits of proposed transmission facilities, the increased opportunities for state engagement in evaluation, selection, and cost allocation, the flexibility for transmission providers in each transmission planning region to determine their own cost allocation methods, and the requirement that any cost allocation method must ensure costs are allocated in a manner that is at least roughly commensurate with estimated benefits provide robust assurance that the cost allocation methods ultimately proposed under the final order will not result in improper cost subsidization. Ultimately, the Commission must review and accept each cost allocation method proposed under the final order to ensure that it is just and reasonable and consistent with the final order's requirements.

269. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, this final order requires transmission providers to use and measure a set of seven required benefits to evaluate Long-Term Regional Transmission Facilities. The measurement of these benefits represents the value that the transmission providers expect a particular Long-Term Regional Transmission Facility to provide to transmission customers in the transmission planning region. As further discussed in the Regional Transmission Planning Cost Allocation section below, this final order requires transmission providers to provide a forum for

[613] *Id.* at 281 (emphasis added).

[614] *Id.*

[615] *Id.*

[616] *Id.*

[617] Order No. 890, 118 FERC ¶ 61,119 at P 3.

[618] Order No. 1000, 136 FERC ¶ 61,051 at P 12.

[619] *EPSA,* 577 U.S. at 281–83.

[620] *Id.* at 282.

[621] *Id.* (citing *Oneok, Inc.* v. *Learjet, Inc.,* 575 U.S. at 385).

[622] Alabama Commission Initial Comments at 8–9; Louisiana Commission Initial Comments at 6, 9–10; Mississippi Commission Reply Comments at 2–3; Ohio Commission Federal Advocate Initial Comments at 4–6; Ohio Consumers Reply Comments at 14.

[623] *See Ill. Com. Comm'n* v. *FERC,* 756 F.3d 556, 562 (7th Cir. 2014) (*ICC* v. *FERC III*); *ICC* v. *FERC I,* 576 F.3d at 477; *Sw. Power Pool, Inc.,* 182 FERC ¶ 61,141, at P 12 (2023).

Relevant State Entities to negotiate a cost allocation method and/or a process for determining future cost allocation methods for Long-Term Regional Transmission Facilities, which enables robust participation by those entities. Moreover, the cost allocation methods required by this final order are intended to ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits that a Long-Term Regional Transmission Facility provides to transmission customers.

270. The benefits this order requires to be used and measured—which provide an important source of transparency regarding any resulting allocation of costs to transmission customers—reflect objective, measurable changes in transmission system conditions, rather than achievement of state public policies. For example, even if a state's public policy is one driver of a Long-Term Transmission Need, these benefits of a Long-Term Regional Transmission Facility resolving that need are well understood and measurable, including, for example, reducing the cost of generating electricity by allowing for the increased dispatch of suppliers that have lower incremental costs of production, minimizing energy losses incurred in transmitting electricity, and lowering the number or duration of loss of load events. Transmission providers will evaluate Long-Term Regional Transmission Facilities for selection considering these benefits that these facilities would provide, and these benefits accrue to the transmission customers that fund their construction. In other words, under this final order, customers pay for a more reliable and economic transmission system as identified through open and transparent Long-Term Regional Transmission Planning, and any state's ratepayers only fund the construction of Long-Term Regional Transmission Facilities that provide them with such benefits that are at least roughly commensurate with the costs of those facilities.

271. We turn now to commenters' specific jurisdiction arguments. As an initial matter, we acknowledge that, in addition to granting authority to the Commission over the transmission of electric energy in interstate commerce, FPA section 201 also reserves certain authority to the states.[624] As such, we agree with Southern that Congress sought in enacting the FPA to ensure the ''continued exercise of state power''[625] over certain matters. However, the requirements in this final order respect and do not unlawfully infringe on state authority. Rather, as discussed above, the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes, which we conclude are unjust and unreasonable.

272. We acknowledge that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable. Effective transmission planning necessarily involves taking into account assumptions about the generation resources that will be available, because transmission needs arise from the relative amounts, locations, and timing of supply (*i.e.,* generation) and of demand (*i.e.,* load); indeed, existing transmission planning processes also take into account these assumptions.[626] Our action in this final order simply modifies the scope and duration of these assumptions to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis by requiring transmission providers to evaluate factors that give rise to Long-Term Transmission Needs.

273. Southern and SERTP Sponsors acknowledge that the NOPR proposed to require transmission providers to incorporate the results of state-sanctioned integrated resource planning as factors in developing Long-Term Scenarios, but they insist that Long-Term Regional Transmission Planning will intrude upon state authority if we do not require Long-Term Scenarios to be *limited* to those state-sanctioned resources.[627] This assertion is incorrect for at least three reasons. First, the public utilities whose integrated resource plans are approved by state commissions are not the only entities whose decisions may influence the development of generation resources within a particular transmission planning region. For example, a wide variety of private enterprises, publicly-owned utilities, and electric cooperatives have made commitments to fund the development of certain generation resources, and transmission providers may reasonably determine that these procurement decisions give rise to Long-Term Transmission Needs. Second, making generation resource assumptions for the purpose of performing transmission planning does not result in any legally-binding determination on a matter within a state's jurisdiction, let alone undermine a state's ability to ultimately decide what generation resources to build, and on what timetable.[628] Third, as Southern and SERTP Sponsors concede,[629] many existing integrated resource planning processes do not identify specific generation resources beyond a particular point in time. Other integrated resource planning processes may not result in a set of state-sanctioned generation resources and may instead serve merely as a guide for the relevant public utility.[630] As a result, relying on such integrated resource planning processes exclusively to identify Long-Term Transmission Needs would fail to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis and therefore would fail to ensure just and reasonable Commission

[624] *See* 16 U.S.C. 824(a)–(b)(1); *New York* v. *FERC,* 535 U.S. at 20–21 (''It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in [*Pub. Utils. Comm'n of R.I.* v. *Attleboro Steam & Elec. Co.,* 273 U.S. 83 (1927) (*Attleboro*)]. The FPA authorized Federal regulation not only of wholesale sales that had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation. More importantly, as discussed above, the FPA authorized Federal regulation of interstate *transmissions* as well as of interstate wholesale sales, and such transmissions were not of concern in *Attleboro.*'' (emphasis in original) (internal citations omitted)).

[625] Southern Initial Comments at 16 (quoting *Oneok, Inc.* v. *Learjet, Inc.,* 575 U.S. at 385).

[626] *See, e.g.,* Xcel Initial Comments at 13, 16 & n.26 (discussing generation resource assumptions made in existing Order No. 1000 regional transmission planning and cost allocation processes).

[627] SERTP Sponsors Initial Comments at 15–17; Southern Initial Comments at 18–19.

[628] We disagree with Southern's and SERTP Sponsors' contention that the inclusion of such non-binding assumptions about generation resources in transmission planning will ''bias'' subsequent state resource decisions. *See* Southern Initial Comments at 19; SERTP Sponsors Initial Comments at 17 n.20. As Kentucky Commission Chair Chandler argues, the NOPR's reforms do not foreclose states' decision making on generation. Kentucky Commission Chair Chandler Reply Comments at 3. We also disagree with North Carolina Commission and Staff's contention that merely requiring transmission providers to use and measure production cost savings in evaluating Long-Term Regional Transmission Facilities ''could conflict with state-jurisdictional resource decisions.'' North Carolina Commission and Staff Initial Comments at 7. If nothing else, Long-Term Regional Transmission Planning will provide public utilities and state commissions the opportunity to develop longer-term, forward-looking, robust assessments that can inform future decision making.

[629] SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 19.

[630] *See, e.g.,* SREA Reply Comments at 2–3 (arguing, in response to Alabama Commission, that Alabama has no formal integrated resource plan process upon which the Commission could encroach).

jurisdictional-rates. To be clear, we are not in this final order attempting to denigrate or diminish the importance of integrated resource planning. Rather, in the context of Long-Term Regional Transmission Planning, integrated resource planning is reasonably considered one of several categories of factors used to develop Long-Term Scenarios and identify Long-Term Transmission Needs.

274. In that light, Southern's and SERTP Sponsors' argument—that we should limit transmission providers to state-approved resources and prohibit non-binding assumptions about the resource mix and demand—does not safeguard but in fact subverts the FPA's division between Federal and state authority. As stated above, were we to require that transmission providers limit their assumptions to only state-sanctioned generation resources, we would be requiring transmission providers to ignore many of the factors that, as demonstrated by this record, transmission providers must reasonably consider to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, it is within our jurisdiction to determine the factors that transmission providers must incorporate in order to identify Long-Term Transmission Needs.

275. Commenters' arguments that the final order would not withstand judicial scrutiny under the ''major questions doctrine'' are similarly unfounded. For example, some commenters appear to misinterpret *West Virginia* v. *EPA* as standing for the proposition that ''the nation's energy policy and generation mix is a 'major question' and that an agency must have direct authorization from Congress to assert jurisdiction'' over these matters.[631] As an initial matter, as noted above, the aim of this final order is not to influence the generation mix or energy policy more broadly, but to ensure that Commission-jurisdictional transmission providers are planning for Long-Term Transmission Needs in a manner that is just and reasonable and results in just and reasonable Commission-jurisdictional rates.

276. In any case, the Court did not determine that energy policy and the mix of generation resources are *in every instance* a major question. Instead, in *West Virginia* v. *EPA,* the U.S. Supreme Court considered a specific agency action in light of a specific statutory provision and concluded that the Environmental Protection Agency's (EPA) exercise of authority was a ''major question'' based on a variety of factors specific to that context—including whether the EPA's administrative action was a ''transformative'' expansion of its power, whether the EPA had relevant technical and policy expertise, whether the relevant statutory provision was ''ancillary'' to the broader statutory construct, and whether the EPA's administrative action implicated significant economic and political questions.[632]

277. Commenters have not attempted a similar analysis of whether courts should construe this final order as a ''major question,'' [633] and we find that their contentions that courts ought to do so are based on the factual mischaracterizations discussed above. In any event, this final order neither transforms nor expands the Commission's authority; it merely applies existing authority, based on the Commission's expertise and experience, to identify and remedy deficiencies in existing regional transmission planning and cost allocation processes.[634] As with Order Nos. 890 and 1000, the Commission is promulgating a final order pursuant to FPA section 206 to address those deficiencies in order to ensure that transmission planning practices, a subject long-regulated by the Commission and well within its area of expertise, remain just and reasonable and not unduly discriminatory or preferential. To that end, this final order requires further reforms to regional transmission planning and cost allocation processes so that they are sufficiently long-term, forward-looking, and comprehensive. And while the transmission planning required in this final order may be more forward-looking, long-term, and comprehensive than the status quo, as a matter of the Commission's jurisdiction, it is fundamentally no different than the regional transmission planning already required by the Commission and upheld by appellate courts.[635] In short, the differences in transmission planning required by this final order represent differences in degree, not kind, from the Commission's longstanding regulations. As such, they are a far cry from the ''transformative expansion'' of the EPA's authority on which the Court relied in *West Virginia* v. *EPA* to find that the issue presented therein represented a major question not delegated to the agency to decide.

278. Just as it is clear that incremental improvements to practices that the courts have already determined fall squarely within the Commission's jurisdiction do not constitute a ''transformative expansion'' or ''extraordinary grant'' of regulatory authority to which the major questions doctrine may apply, so too is it clear that the other ancillary factors cited by the Court are similarly inapplicable. The final order's incremental process improvements, while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the ''vast economic and political significance'' that would implicate the major questions doctrine.[636] The Commission's regulation of interstate transmission rates will have an effect on billions of dollars in customer charges and, in that generic sense, is of political interest to many. The incremental process improvements required by the final order, however, do not fundamentally change the economic or political stakes of ensuring that Commission-jurisdictional rates remain just and reasonable.

279. Likewise, the Commission's continued assertion of authority over regional transmission planning and cost allocation processes does not resemble the EPA's assertion of authority related to the electric system that the Court found to be beyond that agency's expertise.[637] Here, the Commission undisputedly bears the relevant expertise over the interstate transmission system.[638] Nor does the Commission rely on a ''backwater'' statutory provision to achieve its reforms.[639] The Commission relies on FPA sections 205 and 206, which the Court has held ''unambiguously authorize[ ]'' the Commission to assert jurisdiction over interstate

[631] SERTP Sponsors Initial Comments at 17–18; Southern Initial Comments at 20; *see also* Undersigned States Reply Comments at 3 (''National-scale energy grid regulation is a 'major question' because of the massive economic consequences involved in such regulation.'').

[632] *West Virginia* v. *EPA,* 597 U.S. at 710, 724–725, 729, 731–32; *see also Biden* v. *Nebraska,* 143 S. Ct. 2355, 2372–2374 (2023) (applying *West Virginia* v. *EPA's* mode of analysis).

[633] *See* Harvard ELI and Policy Integrity Supplemental Comments at 2 (arguing that Undersigned States, for example, ''overlook key requirements of the major questions doctrine'').

[634] *See, e.g., S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 68–69. *Cf. PJM Power Providers Grp.* v. *FERC,* 88 F.4th at 274.

[635] *See, e.g., S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 48–49; *see also* Harvard ELI and Policy Integrity Supplemental Comments at 4–7.

[636] *West Virginia* v. *EPA,* 597 U.S. at 735 (J. Gorsuch, concurring).

[637] *West Virginia* v. *EPA,* 597 U.S. at 729 (finding relevant that EPA itself admitted it lacked expertise to project ''system-wide trends in areas such as electricity transmission, distribution, and storage'').

[638] *Cf. Amerada Hess Pipeline Corp.* v. *FERC,* 117 F.3d 596, 600–01 (D.C. Cir. 1997) (''[The Federal Energy Regulatory Commission] is entrusted with administering the regulations relating to oil pipelines and has an expertise in the field *based on that jurisdiction.*'' (emphasis added)).

[639] *West Virginia* v. *EPA,* 597 U.S. at 729.

transmission[640] and extends an authority—indeed, a duty—to ensure that the practices directly affecting such rates are just and reasonable.[641] This provision was not ancillary to the statutory scheme but, rather, central to Congress' aim to ensure that the Commission possessed adequate authority to regulate interstate transmission beyond the reach of state power.[642] Finally, commenters do not point to Congress's ''conspicuous[ ] and repeated[ ]'' rejection of legislation that would enact reforms similar to those adopted in the final order.[643]

280. We also disagree with Undersigned States' legal claim that allowing ''one [s]tate [to] effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation'' would violate the Constitution's ''equal sovereignty doctrine.'' [644] As discussed above, the final order categorically does not require states to subsidize other states' public policies or generation decisions. To the contrary, consistent with the cost causation principle, this final order requires customers to pay for a share of the costs of new Long-Term Regional Transmission Facilities only to the extent that *they* benefit from those facilities and, even then, any share they pay for must be roughly commensurate with the benefits they receive.[645]

281. Moreover, according to Undersigned States, the equal sovereignty doctrine dictates that the Nation ''is a union of [s]tates, equal in power, dignity and authority, each competent to exert that residuum of sovereignty not delegated to the United States by the Constitution itself.'' [646] But, ''neither the Supreme Court nor any other court has ever applied that principle as a limit on the Commerce Clause or other Article I powers.'' [647] Instead, Courts have found that ''the Constitution does not contain any textual provision suggesting an equal sovereignty limit on Congress's Article I powers generally or on the Commerce Clause in particular.'' [648] As relevant here, pursuant to the Constitution's Commerce Clause,[649] Congress duly enacted the FPA, which in turn empowers the Commission to regulate the rates and practices affecting rates for the transmission of electricity in interstate commerce.[650] Under the FPA, the Commission is ''unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus . . . .'' [651]

282. The nature of the interconnected transmission system is such that states naturally affect one another in pursuing policies available to them while exercising the authority reserved to them under FPA section 201.[652] For the reasons explained in this final order, we conclude that transmission providers must participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, and we find that transmission providers must have the opportunity to select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Our role within our Federal system is not to ''unreasonably interfere with'' nor to ''pass judgement on state and local policies and objectives,'' [653] including where such policies and objectives have incidental interstate effects.[654] Nor need we, because even if one state's public policy is a driver of a Long-Term Transmission Need, the costs of a Long-Term Regional Transmission Facility that transmission providers select will be allocated to transmission customers only to the extent that they benefit from that facility and only to a degree that is at least roughly commensurate with the benefits that facility provides to them. That approach is consistent with Commission precedent and commenters have not demonstrated that this framework results in impermissible cross-subsidization among states.[655]

283. Finally, in response to NRECA's request, we confirm that the final order is consistent with the Commission's obligation under FPA section 217(b)(4). As articulated in *South Carolina Public Service Authority* v. *FERC,* FPA section 217(b)(4) requires the Commission to ''facilitate the planning of a reliable grid,'' and we do so by ''seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations.'' [656] This final order seeks to ensure precisely the same goal, and it therefore satisfies the Commission's obligation under FPA section 217(b)(4).

B. Development of Long-Term Scenarios

1. NOPR Proposal

284. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission proposed to define Long-Term Scenarios as a tool to identify the transmission planning region's needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. The Commission explained that a scenario is a hypothetical sequence of events that includes assumptions used to forecast transmission needs. The Commission also stated that assumptions used to forecast transmission needs driven by

[640] *New York* v. *FERC,* 535 U.S. at 19.

[641] *EPSA,* 577 U.S. at 277.

[642] *New York* v. *FERC,* 535 U.S. at 20–21 (discussing enactment of FPA in 1935 as a response to *Attleboro*).

[643] *West Virginia* v. *EPA,* 597 U.S. at 745 (J. Gorsuch, concurring).

[644] Undersigned States Reply Comments at 5–6.

[645] *See supra* note 623 and accompanying discussion.

[646] Undersigned States Reply Comments at 5 (citing *Coyle* v. *Smith,* 221 U.S. at 567). *But see Ohio* v. *EPA,* 2024 WL 1515001, at *15 (D.C. Cir. Apr. 9, 2024) (holding that ''[t]he equal footing cases,'' like *Coyle* v. *Smith,* ''do not directly apply either outside of the admission context or to Article I powers like the Commerce Clause.'').

[647] *Ohio* v. *EPA,* 2024 WL 1515001 at *13.

[648] *Id.* at *16.

[649] U.S. Const. art. 1, 8.

[650] 16 U.S.C. 824d.

[651] *PJM Power Providers Grp.* v. *FERC,* 88 F.4th at 275; *see also Elec. Power Supply Ass'n* v. *Star,* 904 F.3d at 524 (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois ''as givens and set out to make the best of the situation [these systems] produce'').

[652] *See Elec. Power Supply Ass'n* v. *Star,* 904 F.3d at 524 (describing the effects on interstate sales resulting from states' exercise of powers reserved to them under FPA section 201 as ''an inevitable consequence of a system in which power is shared between state and national governments'' (citing *Hughes* v. *Talen Energy Mktg., LLC,* 578 U.S. 150, 164 (2016)).

[653] *N.J. Bd. Pub. Utils.* v. *FERC,* 744 F.3d 74, 98 n.24 (3rd Cir. 2014) (quoting *PJM Interconnection, L.L.C.,* 137 FERC ¶ 61,145, at P 3 (2011)); *see also PJM Interconnection, L.L.C.,* 186 FERC ¶ 61,080, at P 186 (2024) (rejecting an argument that the Commission was required to determine whether state-sponsored resources were providing disproportionate benefits to other states in the form of lower capacity market prices).

[654] *See Coal. for Competitive Elec.* v. *Zibelman,* 906 F.3d 41, 56 (2d Cir. 2018) (collecting Commission orders sanctioning state-jurisdictional programs incidentally affecting wholesale markets).

[655] For example, PJM incorporates transmission needs driven by Public Policy Requirements into the assumptions stage of its regional transmission planning process to identify needed reliability and economic regional transmission facilities for potential selection and cost allocation, rather than through a separate and distinct process to identify and allocate the costs of transmission facilities selected to address transmission needs driven by Public Policy Requirements. The Commission found PJM's approach complied with the requirement in Order No. 1000 to consider transmission needs driven by Public Policy Requirements in regional transmission planning and cost allocation processes. *PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, at PP 109–120 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,128, at PP 66–71 (2014).

[656] 762 F.3d at 90.

changes in the resource mix and demand include: forecasts of the level and pattern (*i.e.,* hourly and seasonal variability) of future electricity demand; the quantity, location, and type of resource additions and retirements; and other relevant forecasts about the electric power system that are used as inputs to the transmission model and determine the need for new transmission facilities over the transmission planning horizon. In addition, the Commission noted that other relevant assumptions might include forecasts for natural gas prices, increasing outage trends due to extreme weather and climatic trends, and other future events.

285. The Commission also proposed in the NOPR to require that transmission providers use Long-Term Scenarios to evaluate potential regional transmission facilities needed to meet transmission needs driven by changes in the resource mix and demand to identify the more efficient or cost-effective regional transmission facilities.[657]

2. Comments

a. General Comments

286. Of the commenters specifically addressing the proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning, the majority support scenario-based planning.[658] Clean Energy Buyers state that Long-Term Scenarios are critical to Long-Term Regional Transmission Planning because its success will depend on the quality of forecasting.[659] Form Energy states that long-term scenario review will ensure that transmission upgrades address future needs in a cost-effective and environmentally friendly manner.[660] LADWP asserts that Long-Term Scenarios are critical to developing an effective transmission system that ensures reliability, while also providing flexibility to support the delivery of renewable energy.[661] NARUC states that Long-Term Scenarios are a flexible planning tool for addressing the uncertainty involved in identifying transmission needs driven by changes in the resource mix and demand and that using them will ensure that transmission providers adequately assess the potential benefits of regional transmission facilities.[662]

287. Southeast PIOs claim that Long-Term Scenarios are essential to improving current transmission planning processes in the Southeast.[663] SREA argues that Long-Term Regional Transmission Planning is not occurring in MISO South and states that scenario planning is contentious but necessary.[664]

288. California Energy Commission requests that the Commission clarify that transmission providers may rely on scenarios developed by other agencies, as currently CAISO relies on analyses conducted by California Energy Commission and California Commission.[665] Relatedly, New York Commission and NYSERDA and ISO–NE highlight the importance of state-led identification of public policy needs and their impact on scenario assumptions.[666] New York Commission and NYSERDA state that, especially in a single-state RTO/ISO like NYISO, the state should be afforded a central role in determining the scenarios to be studied.[667] ISO–NE also believes that reliance on states is consistent with prior Commission orders permitting transmission providers to rely on a committee of state regulators to identify transmission needs driven by Public Policy Requirements.[668]

289. PJM States suggest that the Commission's proposal for state involvement in the development of Long-Term Scenarios could be interpreted as more limited than its proposal for state involvement with respect to Long-Term Regional Cost Allocation and ask that the Commission clarify that retail regulators have a primary role in both. PJM States warn that, if a retail regulator disagrees with the scenarios or benefits metrics used to select a transmission project, it is unlikely to receive regulatory approval.[669]

290. Cypress Creek asserts that the Commission should require the use of a defined and standardized set of baseline assumptions to ensure that scenario projections are realistic, and that deviation should only be allowed if the proposal is consistent with or superior to the *pro forma.*[670]

291. Concerned Scientists state that the Commission should reject comments arguing that uncertainty prohibits scenario-based planning, and instead endeavor to create a transmission planning process that properly acknowledges and addresses that uncertainty. Concerned Scientists state that uncertainty does not prohibit long-term transmission planning but rather necessitates the evaluation of multiple plausible scenarios to identify investments that will perform well over a variety of possible future conditions. Concerned Scientists explain that, just as utilities and generator developers do not shy away from an uncertain future when building new generation resources, transmission investments should also be informed by, but not avoided due to, future uncertainty. Concerned Scientists state that the Commission's proposed Long-Term Scenarios requirements are a reasonable minimum for responsible transmission planning.[671]

292. Other commenters support the NOPR proposal to require Long-Term Scenarios in transmission planning but have reservations.[672] Many of these commenters argue that the NOPR is too prescriptive and ask for greater flexibility so that the Long-Term Scenario planning already occurring in their respective transmission planning region will comply with any final order.[673] For example, OMS points to such flexibility as key to the success of MISO's long-term transmission planning

[657] NOPR, 179 FERC ¶ 61,028 at P 84.

[658] *See* ACEG Initial Comments at 6; AEP Initial Comments at 7–8; Amazon Initial Comments at 2–3; BP Initial Comments at 4; California Commission Initial Comments at 1–2, 5–6, 21; California Energy Commission Initial Comments at 1–2; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 11; Duke Initial Comments at 10; Eversource Initial Comments at 10; Exelon Initial Comments at 5; Form Energy Initial Comments at 2–3; GridLab Initial Comments at 10; Handy Law Initial Comments at 9–10; Indicated PJM TOs Initial Comments at 7–8; LADWP Initial Comments at 2; NARUC Initial Comments at 4; National Grid Initial Comments at 10–11; PIOs Initial Comments at 14; PPL Initial Comments at 4; SEIA Initial Comments at 4–5; Southeast PIOs Initial Comments at 42; SREA Initial Comments at 39; State Agencies Initial Comments at 14; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 2; WE ACT Initial Comments at 3; WIRES Initial Comments at 6.

[659] Clean Energy Buyers Initial Comments at 11.

[660] Form Energy Initial Comments at 3.

[661] LADWP Initial Comments at 2.

[662] NARUC Initial Comments at 4.

[663] Southeast PIOs Initial Comments at 42, 46.

[664] SREA Initial Comments at 39–41.

[665] California Energy Commission Initial Comments at 2.

[666] New York Commission and NYSERDA Initial Comments at 7; ISO–NE Initial Comments at 25–26.

[667] New York Commission and NYSERDA Initial Comments at 8.

[668] ISO–NE Initial Comments at 25 (citing *ISO New England Inc.,* 143 FERC ¶ 61,150, at P 108 (2013)).

[669] PJM States Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

[670] Cypress Creek Reply Comments at 5–8.

[671] Concerned Scientists Reply Comments at 18–19.

[672] Ameren Initial Comments at 7–8; American Municipal Power Initial Comments at 7; APPA Initial Comments at 25; CAISO Initial Comments at 21; Chemistry Council Initial Comments at 5; Michigan Commission Initial Comments at 4–5; MISO TOs Initial Comments at 15–17; Omaha Public Power Initial Comments at 3–4; OMS Initial Comments at 3–5; PJM Initial Comments at 54.

[673] CAISO Initial Comments at 21; Michigan Commission Initial Comments at 4–5; MISO TOs Initial Comments at 15–16; OMS Initial Comments at 3–4.

processes.[674] SERTP Sponsors argue that the Commission should not make Long-Term Scenarios even more prescriptive because such an approach would likely result in litigation and delay.[675]

293. American Municipal Power believes that transmission providers should conduct Long-Term Scenarios in a highly collaborative way with the full and active participation of all stakeholders.[676] Similarly, Six Cities recommend that Long-Term Scenarios be coordinated between state and local regulatory authorities to reflect varying policies. Six Cities recommend that, in CAISO, Long-Term Scenarios should consider the procurement choices of non-jurisdictional utilities, such as Six Cities, as well as policy portfolios provided by California Commission.[677]

294. Some commenters oppose the NOPR proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning.[678] Dominion argues for maximum flexibility for planning assumptions to support reliable and affordable transmission service for customers.[679] Idaho Commission states that any prescription for scenario analysis should be supported by clear evidence of a deficiency.[680] Instead of specific scenario planning requirements, Nebraska Commission states that the Commission should provide general guidelines and as much flexibility as possible to transmission providers, who—along with state regulatory officials—are best situated to evaluate the needs of each transmission planning region.[681]

295. Potomac Economics questions the NOPR's proposal to require Long-Term Scenarios, stating that it will force RTOs/ISOs to plan and commit to sizable transmission investment costs based on uncertain factors and unreasonable speculation on factors such as the location of future generation, retirements, grid enhancing technologies, and transmission reconfiguration options.[682] Potomac Economics also questions the usefulness of Long-Term Scenarios, asserting that future congestion patterns will be increasingly uncertain given that the higher penetration of intermittent resources will cause larger fluctuations in transmission flows, making it more difficult to accurately estimate the benefits of transmission upgrades.[683] Potomac Economics argues that many of the most beneficial transmission upgrades address very specific constraints, are smaller in size, can be difficult to identify in advance, and can be very sensitive to modest changes in generation and load.[684]

[674] OMS Initial Comments at 4–5.

[675] SERTP Sponsors Reply Comments at 13–14.

[676] American Municipal Power Initial Comments at 7.

[677] Six Cities Initial Comments at 4.

[678] Dominion Initial Comments at 10; Idaho Commission Initial Comments at 3; Nebraska Commission Initial Comments at 3; Ohio Consumers Initial Comments at 2, 5; Potomac Economics Initial Comments at 2.

[679] Dominion Initial Comments at 10–12.

[680] Idaho Commission Initial Comments at 3.

[681] Nebraska Commission Initial Comments at 3.

[682] Potomac Economics Initial Comments at 2, 4.

b. Applying Scenario Planning to Reliability and Economic Planning

296. California Commission and City of New York assert that the Commission should require the use of Long-Term Scenarios in all transmission planning processes—not just Long-Term Regional Transmission Planning.[685] City of New York argues that such a requirement would enable consideration of a broad range of potential future system conditions across multiple planning categories.[686] Similarly, NYISO states that the final order should authorize, but not require, the use of multiple alternative scenarios in existing transmission planning processes. NYISO states that doing so would enhance its ability to anticipate and solicit more efficient, holistic transmission solutions, which would support system reliability and resilience.[687]

297. In contrast, certain commenters oppose requiring transmission providers to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes.[688] Duke contends that the Commission should avoid disrupting existing regional transmission planning processes that work well.[689] MISO notes that, while this type of scenario-based planning has been applied to economic transmission planning processes and could be applied to existing reliability transmission planning processes, such application should be flexible and tailored to the unique needs of each transmission provider, adding that scenario-based planning requires considerable time and resources.[690]

[683] *Id.* at 2.

[684] *Id.* at 3.

[685] California Commission Initial Comments at 22–24; City of New York Initial Comments at 7.

[686] City of New York Initial Comments at 7.

[687] NYISO Initial Comments at 14–15.

[688] Duke Initial Comments at 2, 10–11; Eversource Initial Comments at 19; MISO Initial Comments at 32; NESCOE Initial Comments at 23; PJM Initial Comments at 54–56.

[689] Duke Initial Comments at 2, 10–11.

[690] MISO Initial Comments at 32.

3. Commission Determination

298. We adopt, with modification, the NOPR proposals to require transmission providers in each transmission planning region to (1) develop and use Long-Term Scenarios as part of Long-Term Regional Transmission Planning and (2) use those Long-Term Scenarios to identify and evaluate Long-Term Regional Transmission Facilities needed to meet Long-Term Transmission Needs. As further explained in subsequent sections of this final order, we find that these requirements regarding the development and use of Long-Term Scenarios in Long-Term Regional Transmission Planning strike a reasonable balance between ensuring that Long-Term Regional Transmission Planning reasonably identifies Long-Term Transmission Needs over a sufficiently long-term, forward-looking transmission planning horizon and providing sufficient flexibility for transmission providers to develop and use Long-Term Scenarios in a way that reflects the unique characteristics of their respective transmission planning regions.

299. We first address the definition of Long-Term Transmission Needs. For purposes of this final order, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final order, running scenarios and considering the enumerated categories of factors. As explained in the NOPR, the drivers of transmission needs are diverse and include, but are not limited to, evolving reliability concerns, changes in the resource mix, and changes in demand. For example, as identified in the NOPR, reliability concerns giving rise to Long-Term Transmission Needs include, among other things, the increasing frequency of high-impact extreme weather events, the increasing reliance by transmission system operators on regional integration and coordination to reliably serve load, the operational challenges created by the increasing share of variable resources entering the resource mix, and changes in electric demand patterns such as shifts in load profiles caused by, for example, the emergence of large loads associated with evolving industrial and commercial needs such as the growth in data centers, and increased electrification of energy end uses.[691]

300. In the NOPR, the Commission referred to transmission needs identified through Long-Term Regional Transmission Planning largely as needs

[691] *See* NOPR, 179 FERC ¶ 61,028 at PP 45, 51.

driven by changes in the resource mix and demand.[692] Nevertheless, we agree with commenters who correctly note that there are additional drivers of Long-Term Transmission Needs,[693] and, as noted above, the Commission itself contemplated in the NOPR that Long-Term Regional Transmission Planning would consider drivers beyond those tied directly to changes in supply and demand. We therefore clarify that, although changes in the resource mix and demand are important drivers of Long-Term Transmission Needs, they represent only a subset of such drivers. In addition, we note that Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000. Where Long-Term Transmission Needs differ is their identification through the long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes established in this final order. Accordingly, in this final order, we refer to the transmission needs that are identified through Long-Term Regional Transmission Planning as Long-Term Transmission Needs. The identification of Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to potentially meet those needs is accomplished through the use of Long-Term Scenarios in Long-Term Regional Transmission Planning.

301. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section of this final order, we require transmission providers to measure and use a set of seven required benefits in Long-Term Regional Transmission Planning. Transmission providers must use this same set of benefits to help to inform their identification of Long-Term Transmission Needs. For example, in this final order we require transmission providers to measure and use production cost savings in Long-Term Regional Transmission Planning. As such, when transmission providers are working to identify Long-Term Transmission Needs, areas of significant congestion on the transmission system—where Long-Term Regional Transmission Facilities could reduce congestion and in turn facilitate production cost savings—may indicate a Long-Term Transmission Need.

302. We adopt the definition of Long-Term Scenarios proposed in the NOPR,[694] with modification. We define Long-Term Scenarios as scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs. We make this modification to clarify the intent of the definition proposed in the NOPR, rather than modify the definition in substance.

303. Certain commenters assert that the Commission should not require transmission providers to develop Long-Term Scenarios due to the inherent uncertainty of forecasting future transmission needs over a long transmission planning horizon. We acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs. However, we believe that such uncertainty is mitigated by using Long-Term Scenarios themselves, as noted by Concerned Scientists and NARUC.[695] Scenario planning allows transmission providers to evaluate whether Long-Term Regional Transmission Facilities are beneficial in more than one scenario. Transmission providers may also examine whether Long-Term Transmission Needs appear in one or more scenarios. Scenario planning also allows transmission providers to consider a broader range of future circumstances and be better prepared for changes in the electric power system.[696] Finally, transmission providers may use scenario planning to determine whether identified Long-Term Regional Transmission Facilities provide sufficient benefits across more than one scenario when considering whether to select such facilities, as also noted by NARUC.[697] Moreover, we adopt requirements for Long-Term Scenarios, as discussed further below, to ensure they are based on reasonable assumptions and better reflect future transmission system conditions and uncertainties in those future circumstances. In sum, incorporating Long-Term Scenarios into Long-Term Regional Transmission Planning provides an appropriate approach to ensure just and reasonable rates by accounting for the increasing uncertainty in the accuracy of assumptions over longer (*i.e.,* over 10 years) transmission planning horizons and mitigating the risks of under-building or over-building Long-Term Regional Transmission Facilities.

304. Further, we disagree with commenters that suggest that the Commission should not establish specific Long-Term Scenario requirements and that imposing general principles is sufficient to ensure just and reasonable rates. We find that Long-Term Regional Transmission Planning that does not incorporate Long-Term Scenarios that meet the requirements of this final order would fail to ensure that transmission providers identify Long-Term Transmission Needs, as well as identify and evaluate Long-Term Regional Transmission Facilities to address those needs. For example, relying on a single forecast of future transmission system conditions may limit transmission providers' and stakeholders' confidence in identified Long-Term Transmission Needs, and accordingly the evaluation of Long-Term Regional Transmission Facilities to address those needs. Further, failure to incorporate Long-Term Scenarios would increase the likelihood of piecemeal and relatively inefficient or less cost-effective transmission development. Accordingly, we find that requiring transmission providers to develop and use Long-Term Scenarios that meet the requirements established in this final order as part of Long-Term Regional Transmission Planning will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

305. Additionally, as stated above and in response to commenters that emphasize the importance of

[692] *Id.*

[693] *See, e.g.,* AEE Initial Comments at 7–8 (noting that reforms are needed to meet transmission needs driven by "market forces, state policies, and new reliability and resilience imperatives"); ELCON Initial Comments at 4 ("[L]ong term scenario planning should not be limited to anticipated resource mix but also take into consideration impacts on reliability and congestion management."); New Jersey Commission Initial Comments at 2 ("[T]he Board stresses that most of the reforms the Commission is proposing would be necessary even in the absence of 'changes in the resource mix and demand.' ") (citing NOPR, 179 FERC ¶ 61,028 at P 24); Renewable Northwest Initial Comments at 8 (noting how current transmission planning processes ignore both "trends in future generation and the impact of extreme weather events") (citing NOPR, 179 FERC ¶ 61,028 at P 51); Southeast PIOs Initial Comments at 7–8 (noting that both intensifying "changes in the generation mix" and "increasingly common extreme weather and high-intensity, low frequency events" burden the existing transmission system).

[694] In the NOPR, the Commission proposed to define Long-Term Scenarios as a tool to identify transmission needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. NOPR, 179 FERC ¶ 61,028 at P 84.

[695] Concerned Scientists Reply Comments at 18–19; NARUC Initial Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 86, 88).

[696] *See* Policy Integrity Reply Comments at 2.

[697] NARUC Initial Comments at 4.

collaboration in developing Long-Term Scenarios, this final order retains the requirements for an open, coordinated, and transparent local transmission planning process established in Order No. 890 and further required for regional transmission planning in Order No. 1000.[698] For example, consistent with the transparency transmission planning principle,[699] transmission providers must make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario. Moreover, as described below, this final order requires that transmission providers provide meaningful opportunity for stakeholder input, including from state and local regulators, as well as non-jurisdictional entities, into the factors used to develop Long-Term Scenarios.

306. In response to PJM's request that the Commission clarify that the role of the state regulator is primary in developing Long-Term Scenarios, we note that, as described in the Stakeholder Process and Transparency determination within the Categories of Factors section, transmission providers retain the ultimate responsibility for transmission planning.[700] As such, transmission providers have discretion, subject to the limits imposed in this final order, to weigh more heavily one source of information over another, such as weighing information related to a factor provided by a state regulator more heavily than information provided by other stakeholders. In response to California Energy Commission, we find that the final order does not preclude transmission providers from relying on scenarios developed by state agencies, provided that the Commission finds that the OATT provisions governing those Long-Term Scenarios' development comply with the Long-Term Scenarios requirements of this final order (*e.g.,* transmission planning horizon and stakeholder input requirements). We decline to require the use of Long-Term Scenarios in all transmission planning processes, as requested by California Commission and City of New York. The record in this proceeding does not demonstrate that the incorporation of Long-Term Scenarios in existing Order No. 1000 regional transmission planning processes is necessary to ensure that Long-Term Regional Transmission Planning is just and reasonable. In response to NYISO's request that transmission providers be allowed to use scenario planning in their existing Order No. 1000 regional transmission planning processes, while we agree that such a practice may offer benefits, we find that any such request amending existing transmission planning processes must be submitted in an FPA section 205 filing separate from their compliance filings to this final order.[701]

C. Long-Term Scenarios Requirements

1. Transmission Planning Horizon

a. NOPR Proposal

307. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[702]

308. The Commission preliminarily found that a 20-year transmission planning horizon requirement strikes a reasonable balance between the current transmission planning horizons used in many transmission planning regions and the 30-year or longer transmission planning horizon proposed by some ANOPR commenters. The Commission noted that the 30-year or longer transmission planning horizon was criticized by other commenters as speculative or too uncertain. The Commission also stated that a 20-year transmission planning horizon requirement may be reasonable because some transmission providers use a 20-year transmission planning horizon in existing regional transmission planning processes. In addition, the Commission stated that a 20-year transmission planning horizon would allow for sufficient time to identify, plan, and obtain siting and permitting approval for and to construct regional transmission facilities to meet long-term regional transmission needs, including those that may take longer than the average amount of time to go from the planning stage to in-service. Finally, the Commission stated that a 20-year transmission planning horizon would allow transmission providers to better leverage economies of scale by sizing transmission facilities to meet not only nearer-term transmission needs, but also longer-term transmission needs driven by changes in the resource mix and demand over time. The Commission preliminarily found that by assessing transmission needs over a longer time horizon—for example, starting in year six[703] through year 20 of the transmission planning horizon—Long-Term Regional Transmission Planning should be able to identify more efficient or cost-effective regional transmission facilities to address these needs.[704]

b. Comments

i. Support for 20-Year Transmission Planning Horizon

309. Many commenters support the Commission's proposal to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[705] Several

[698] Order No. 1000, 136 FERC ¶ 61,051 at PP 150–152; Order No. 890, 118 FERC ¶ 61,119 at P 435.

[699] Order No. 890, 118 FERC ¶ 61,119 at P 471.

[700] *Id.* P 454. There, we stated in response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in the final rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.

[701] We note that an exception to the requirement to file a separate FPA section 205 filing applies if transmission providers were to propose a unified transmission planning process, as discussed above. *See supra* Participation in Long-Term Regional Transmission Planning section.

[702] NOPR, 179 FERC ¶ 61,028 at PP 97–100.

[703] The Commission noted that the North American Electric Reliability Corporation defines the long-term transmission planning horizon as covering year six through year 10 and beyond. *Id.* P 94 n.160.

[704] *Id.* PP 97–99 (footnotes omitted).

[705] ACORE Initial Comments at 1; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8; AEP Initial Comments at 5, 8–12; Amazon Initial Comments at 2–3; BP Initial Comments at 4–5; Breakthrough Energy Initial Comments at 12–13; Breakthrough Energy Supplemental Comments at 1; California Water Initial Comments at 14–15; Certain TDUs Initial Comments at 3, 19; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 12; Clean Energy States Initial Comments at 2; Concerned Scientists Reply Comments at 18–19; Cypress Creek Reply Comments at 4; DC and MD Offices of People's Counsel Initial Comments at 8; Environmental Groups Supplemental Comments at 2; Eversource Initial Comments at 14; Form Energy Initial Comments at 2; Georgia Commission Initial Comments at 2–3; GridLab Initial Comments at 5; Idaho Power Initial Comments at 4; Illinois Commission Initial Comments at 6; Indicated US Senators and Representatives Initial Comments at 1; Interwest Initial Comments at 4–5; ITC Initial Comments at 9–11; LADWP Initial Comments at 2; Minnesota State Entities Initial Comments at 4; National and State Conservation Organizations Initial Comments at 1; National Grid Initial Comments at 12–13; Nevada Commission Initial Comments at 7; New England for Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 9–10; NextEra Initial Comments at 62; NYISO Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 2; PG&E Initial Comments at 2; Policy Integrity Initial Comments at 10; PIOs Initial Comments at 15; R Street Initial Comments at 6; SEIA Initial Comments at 6; SoCal Edison Initial Comments at 11–12; Southeast PIOs Initial Comments at 43; SPP Initial Comments at 5–6; SPP Market Monitor Initial Comments at 4–5; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments at 2); US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 10; Vermont Electric and Vermont Transco Initial

Continued

commenters generally consider a 20-year transmission planning horizon to be reasonable, acceptable, or appropriate.[706] Some commenters argue that a 20-year transmission planning horizon provides a reasonable balance between shorter- and longer-term transmission planning horizons.[707] National Grid states that a 20-year transmission planning horizon balances the benefits of prospective transmission planning with the greater uncertainty that comes with forecasting system needs over a longer period.[708] Numerous commenters argue that a 20-year transmission planning horizon will help to improve the efficiency and cost of developing transmission and to assess future transmission needs.[709]

310. New Jersey Commission argues that a 20-year transmission planning horizon should help to make long-term multi-driver transmission projects viable by identifying needs and opportunities in a timeframe that allows states to have a meaningful conversation about voluntarily funding such projects.[710] Policy Integrity argues that it is crucial to model what is going to be needed *over* the next 20 years to ensure that short- and medium-term transmission projects are built efficiently, stating that a longer transmission planning horizon is reasonable in the context of long-lived transmission assets with long lead times.[711]

311. US DOE asserts that there is sufficient evidence to extend the transmission planning horizon to a minimum of 20 years for Long-Term Regional Transmission Planning to capture power sector changes that occur during transmission development.[712] PIOs note that panelists at the November 2021 Technical Conference suggested a 20-year transmission planning horizon is necessary, in part, due to long-term public policy goals.[713] Acadia Center and CLF similarly argue that transmission planners should plan over long-term horizons to factor in predictable trends, such as timelines required under state laws and policies.[714]

312. Several commenters emphasize that a transmission planning horizon of 20 years is sufficient to account for the amount of time needed to develop transmission projects, considering the complexity and challenges of major transmission development.[715] Eversource states that a long-term perspective is necessary to take advantage of the economies of scale that large transmission projects can enable, as well as to incorporate anticipated changes in generation and load beyond the traditional transmission planning horizon.[716] Illinois Commission states that a 20-year transmission planning horizon is necessary to properly plan and build transmission and generation resources.[717] LADWP states that a 20-year transmission planning horizon provides enough time for transmission projects to be developed and placed in service when such projects require new rights-of-way without becoming too speculative.[718] NextEra contends that a 20-year transmission planning horizon will ensure that transmission planners anticipate and plan transmission facilities for needs driven by changes in the resource mix and demand.[719]

313. PIOs state that a 20-year transmission planning horizon should be the minimum timeframe, explaining that because transmission facilities can take 15 years to plan, permit, and construct, a 20-year transmission planning horizon can result in just-in-time planning, where the transmission plan is developed shortly before the process for siting and permitting must begin.[720] GridLab asserts that a 20-year transmission planning horizon might identify regional transmission needs that occur after year 10, as well as transmission projects that would be selected and approved in later transmission planning cycles.[721]

314. Clean Energy States support quick adoption of at least a 20-year planning horizon because many of their member states have established 100% clean energy power sector or zero-carbon goals for their state economies by 2040 or 2050.[722] California Municipal Utilities, on the other hand, support a 20-year transmission planning horizon, but caution that transmission costs identified can be significant and could rely upon speculative resources that may not come to fruition, namely off-shore wind development.[723]

315. Many commenters highlight transmission planning regions with existing long-term transmission planning that either does or will conform to the 20-year transmission planning horizon proposed in the NOPR.[724] MISO commits to continue using its 20-year forecast period under this proposed reform.[725] SPP states that it currently performs a 20-year assessment that incorporates Long-Term Scenarios at least once every five years.[726] New York Transco notes that NYISO's transmission planning process utilizes multiple cases and scenarios over a 20-year evaluation horizon.[727] Acadia Center and CLF note that ISO–NE recently gained Commission approval for longer-term transmission studies to undertake long-term transmission planning to 2050.[728]

316. CAISO states that it currently approves transmission projects in its annual transmission planning process based on a 10-year outlook, although the CAISO OATT allows for a longer 20-year transmission horizon outlook to reliably and cost-effectively account for California's greenhouse gas and renewable energy objectives.[729] CAISO explains that its 20-year outlook does not include a process for approving specific transmission projects, but rather allows considerations beyond 10 years to inform decisions in its annual

Comments at 2; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

[706] CAISO Initial Comments at 21; EEI Initial Comments at 11; Entergy Initial Comments at 9; NARUC Initial Comments at 5; New York TOs Initial Comments at 10; Pine Gate Initial Comments at 19–20; PPL Initial Comments at 6; WIRES Initial Comments at 7.

[707] DC and MD Offices of People's Counsel Initial Comments at 8–9; LADWP Initial Comments at 2–3; National Grid Initial Comments at 12–13.

[708] National Grid Initial Comments at 12–13.

[709] AEP Reply Comments at 4–5 (citing MTEP2017 Review at 33–34); Amazon Initial Comments at 2–3; BP Initial Comments at 5; Certain TDUs Reply Comments at 5; PIOs Initial Comments at 15.

[710] New Jersey Commission Initial Comments at 9–10, 28.

[711] Policy Integrity Initial Comments at 10.

[712] US DOE Initial Comments at 10.

[713] PIOs Initial Comments at 15 (citing Tr. 129–137 (multiple witnesses)).

[714] Acadia Center and CLF Initial Comments at 4.

[715] Eversource Initial Comments at 14; Illinois Commission Initial Comments at 6; LADWP Initial Comments at 2; NextEra Initial Comments at 62–63; PG&E Initial Comments at 2; PIOs Initial Comments at 15.

[716] Eversource Initial Comments at 14.

[717] Illinois Commission Initial Comments at 6.

[718] LADWP Initial Comments at 2.

[719] NextEra Initial Comments at 62–63.

[720] PIOs Initial Comments at 15.

[721] GridLab Initial Comments at 8–9.

[722] Clean Energy States Initial Comments at 2.

[723] California Municipal Utilities Initial Comments at 6–7.

[724] Acadia and CLF Initial Comments at 3; CAISO Initial Comments at 15; California Municipal Utilities Initial Comments at 5–6; Clean Energy States Initial Comments at 2; ISO/RTO Council Initial Comments at 3–4; MISO Initial Comments at 33; MISO TOs Initial Comments at 17; New York TOs Initial Comments at 2; New York Transco Initial Comments at 5; NextEra Initial Comments at 63–64 (discussing efforts at CAISO, SPP, and MISO); Omaha Public Power Initial Comments at 4; PIOs Initial Comments at 14 (pointing to NYISO and MISO as examples of transmission planning regions already successfully using a 20-year transmission planning horizon); SPP Initial Comments at 5–6.

[725] MISO Initial Comments at 33.

[726] SPP Initial Comments at 5–6.

[727] New York Transco Initial Comments at 5 (citing NYISO, NYISO Tariffs, NYISO OATT, attach. Y section 31.4a (Public Policy Requirements Planning Process) (23.0.0), section 31.4.6.1).

[728] Acadia Center and CLF Initial Comments at 3.

[729] CAISO Initial Comments at 15.

transmission planning process.[730] California Municipal Utilities also highlight CAISO's existing transmission planning processes, noting that its 20-year transmission outlook calls for an estimated combined capital cost of $30.5 billion.[731] NextEra notes that, while many transmission planning regions use or will use a 20-year transmission planning horizon, no requirements exist to ensure that these practices persist.[732]

317. Several commenters reference existing long-term planning processes as support for the Commission's proposed 20-year transmission planning horizon.[733] NextEra and ACEG explain that longer time horizons are embedded into existing integrated resource plans, through law or common practice, and extend into and beyond 2040 to meet ambitious resource goals.[734] R Street argues that, for benchmarking purposes, 20- to 25-year planning horizons have been a best practice for integrated resource planning for decades.[735]

318. LADWP asserts that the proposed 20-year transmission planning horizon is likely the least disruptive horizon because of its current use by many transmission providers. LADWP further argues that a consistent transmission planning horizon will optimize asset investment and minimize public impacts; facilitate planning, coordination, and development of large-scale regional transmission projects; and ensure that transmission providers consider the same end point assessments of the evolving resource mix, environmental requirements that develop beyond a typical 10-year period, and significant maintenance and retirement issues.[736]

ii. Requests for Flexibility

319. Several commenters recommend that the Commission provide transmission providers in each transmission planning region with the flexibility to propose other transmission planning horizons that may be appropriate and beneficial based on their planning processes.[737] APS states that it is not convinced that a prescriptive approach will yield the benefits that the Commission seeks.[738]

320. NESCOE states that there is not one ''right'' transmission planning horizon and that it does not support a one-size-fits-all transmission planning horizon requirement.[739] NESCOE requests that the Commission allow transmission providers in each transmission planning region to demonstrate that existing tariff provisions are consistent with or superior to a final order mandating a minimum transmission planning horizon, explaining—along with ISO–NE—that ISO–NE's Tariff does not provide a prescribed timeframe to request transmission analyses based on state-provided scenarios.[740] Relatedly, California Commission suggests that, instead of mandating a 20-year transmission planning horizon, the Commission should adopt NYISO's recommendation to provide transmission providers with the discretion, up to 20 years, to plan for their needs.[741]

321. PG&E understands that not every transmission need identified in the latter years of a 20-year transmission planning horizon will require immediate selection resolution, and it therefore asks the Commission to give individual transmission planning regions the flexibility to determine how to allow for monitoring and updating planning assumptions for transmission projects that meet transmission needs beyond 10 years.[742] ISO–NE argues that the Commission should permit an approach that allows (but does not require) a transmission planning horizon beyond 10 years because the 20-year transmission planning horizon could potentially limit the identification of system issues during interim years, inhibit adaptation to evolving policies, and preclude the transmission planning process from considering public policies that may include shorter timeframes, which may limit the ability to adapt to emerging needs or changing laws.[743] NESCOE contends that a rigid 20-year transmission planning horizon may be counterproductive and could divert resources focused on meeting requests under ISO–NE's longer-term transmission planning process to study a time horizon that states, stakeholders, and ISO–NE may not find useful.[744]

322. OMS argues that the final order should permit flexibility in transmission planning horizons and enable transmission planning regions to meet objectives through routine scenario-based planning within an appropriate study window.[745] Industrial Customers assert that transmission planning horizons should consider the time to identify, plan, and obtain siting and permitting approval to construct regional transmission facilities, and that timing can vary dramatically by region. Industrial Customers believe a stringent 20-year transmission planning horizon could create more uncertainty, resulting in stranded transmission investments and increased transmission rates because it is difficult, if not impossible, to forecast transmission needs and requirements 20 years into the future.[746]

323. PJM States recommend, and Clean Energy Associations agree, that instead of requiring a transmission planning horizon of a particular length, the Commission should require each transmission provider to demonstrate that the transmission planning horizon it chooses is adequate to achieve the goals of Long-Term Regional Transmission Planning.[747]

324. New York State Department recommends that the final order allow states to determine the appropriate transmission planning horizon since New York Public Service Commission has already issued orders directing long-term transmission and distribution

[730] *Id.* at 15–16.

[731] California Municipal Utilities Initial Comments at 5–6 (citing CAISO, *20-Year Transmission Outlook,* Table ES–1: Cost estimate of transmission development to integrate resources of SB100 Starting Point scenario (Jan. 31, 2022), *http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf*).

[732] NextEra Initial Comments at 64–65.

[733] BP Initial Comments at 5 (citing CAISO's transmission planning process); Idaho Power Initial Comments at 4 (noting NorthernGrid's 20-year transmission planning horizon); Interwest Initial Comments at 5 (noting existing state resource planning processes); Nevada Commission Initial Comments at 7 (noting its integrated resource planning process requiring a minimum of eight years); PIOs Initial Comments at 14 (noting 20-year horizons used by NYISO, MISO, and other transmission planning regions); SPP Market Monitor Initial Comments at 4–5 (noting SPP's existing transmission planning process); Western PIOs Initial Comments at 28–29 (noting Western Electricity Coordinating Council's planning scenarios and the integrated resource planning timelines of western vertically-integrated utilities).

[734] ACEG Reply Comments at 4–5; NextEra Initial Comments at 62–63.

[735] R Street Initial Comments at 6.

[736] LADWP Initial Comments at 2.

[737] Ameren Initial Comments at 13; APPA Initial Comments at 5; California Water Initial Comments at 14–15; EEI Initial Comments at 11; Indicated PJM TOs Initial Comments at 10; ISO–NE Initial Comments at 22–23; MISO TOs Initial Comments at 17; NARUC Initial Comments at 5–6; NESCOE Initial Comments at 25; New York State Department Initial Comments at 3; New York TOs Initial Comments at 10; Pennsylvania Commission Initial Comments at 5; TANC Initial Comments at 10; WIRES Initial Comments at 7; Xcel Initial Comments at 9.

[738] APS Initial Comments at 3.

[739] NESCOE Initial Comments at 23–24.

[740] ISO–NE Initial Comments at 22–23; NESCOE Initial Comments at 24–25.

[741] California Commission Initial Comments at 11–12 (citing NYISO ANOPR Initial Comments at 37).

[742] PG&E Initial Comments at 4–6.

[743] ISO–NE Initial Comments at 22–23.

[744] NESCOE Initial Comments at 24–25.

[745] OMS Initial Comments at 4–5.

[746] Industrial Customers Reply Comments at 4–5.

[747] Clean Energy Associations Reply Comments at 5–6; PJM States Initial Comments at 4.

planning with undefined terms.[748] EEI and US Chamber of Commerce explain that state regulators may not appreciate a rigid 20-year transmission planning horizon requirement given that some state resource procurement processes use a 10-year outlook, and the proposed transmission planning process may thus make resource decisions that are not state-sanctioned.[749] Consistent with their Coordinated Grid Planning Process, New York Commission and NYSERDA assert that the Commission should allow state regulators to help determine the appropriate transmission planning horizon, especially in a single-state RTO/ISO such as NYISO.[750]

325. Louisiana Commission states that a 20-year transmission planning horizon may be longer than the planning horizon utilized in state integrated resource planning, explaining that its integrated resource planning rules allow for a 20-year default planning period, but also for alternative periods, and more importantly, require 5-year action plans.[751]

326. APPA argues, and TANC concurs, that the Commission should allow transmission planning regions to incorporate cost and benefit-tracking mechanisms to reduce the risk of speculative transmission projects.[752]

iii. Requests for a Different Transmission Planning Horizon

327. Several commenters argue that a 20-year transmission planning horizon is too long.[753] Indicated PJM TOs contend that the Commission should ensure that transmission planning horizons result in the identification of transmission facilities that can be realistically planned and developed, and that 20 years may be too long given rapidly changing technology, generation mix, and demand patterns.[754] Mississippi Commission also favors a shorter transmission planning horizon, arguing that there is too much uncertainty to plan 20 to 40 years into the future.[755] NRECA argues that a 20-year transmission planning horizon may allow more alternatives to be considered, but cost efficacy is not guaranteed. Further, NRECA argues that planning beyond 10 years will by necessity devolve into a top-down process that would, at best, relegate actual load-serving entity resource plans and demand forecasts to a secondary status or, at worst, ignore them altogether, violating FPA section 217(b)(4).[756]

328. PJM Market Monitor states that uncertainty increases significantly as the transmission planning horizon is extended, and the transmission planning process should be both long-term and flexible, allowing transmission planners to change plans as reality changes.[757] Similarly, US Chamber of Commerce asserts that, as the length of the transmission planning horizon increases, the number of assumptions increases and the quality of assumptions decreases, rendering costs and benefits less certain. US Chamber of Commerce states that today's transmission grid was not forecasted at the turn of the century, and, thus, forecasts made today for a similar period are likely to under or over-shoot transmission needs due to new and advancing generation technologies with commercial operation timeframes not yet known.[758] Nebraska Commission states that a 20-year transmission planning horizon may reduce the transmission planning process to an academic exercise due to the amount of speculation necessarily involved.[759]

329. Industrial Customers state that the Commission has not ruled against transmission planning horizons under 15 years and has acknowledged that the average time needed to develop and build a transmission project is 10 years.[760] Industrial Customers assert that, contrary to the Commission's view, most transmission planners use 10-year transmission planning horizons, and transmission investment should be driven by shorter timeframes to plan for economic and reliability needs.[761] Ohio Consumers note that the 5-year timeframe used by PJM's DFAX method is characterized by high uncertainty, so a longer timeframe would exacerbate inaccuracies.[762]

330. Several commenters argue that a 10-year transmission planning horizon could reduce speculation, such as with respect to the changing resource mix.[763] NRG states that a shorter, 10-year transmission planning horizon would fit within the time horizon necessary to make transmission investment decisions and still reflect regional policy goals.[764] Utah Commission notes that NorthernGrid's members in 2020 adopted a 10-year transmission planning horizon and objects to being compelled to abandon that planning horizon in favor of a one-size-fits-all mandate.[765]

331. PJM and Exelon advocate for a 15-year transmission planning horizon to reduce uncertainty and enhance reliability.[766] Exelon argues that a 15-year transmission planning horizon may yield less uncertain forecasts that are more likely to be actionable and better align with target dates in public policies.[767] PJM argues that its current 15-year transmission planning horizon is sufficient to plan and develop needed transmission, and that forecasts of fuel prices, load trends, generation retirement, and other relevant parameters become more uncertain the further one looks out. Moreover, PJM asserts, a longer transmission planning horizon leads to a greater probability that a transmission provider will commit to a transmission project that will look unfortunate in hindsight.[768]

332. Some commenters argue that a transmission planning horizon longer than 20 years may be warranted to capture the longer-term benefits of transmission facilities.[769] ACEG recommends that the Commission

[748] New York State Department Initial Comments at 3.

[749] EEI Initial Comments at 11; US Chamber of Commerce Initial Comments at 6.

[750] New York Commission and NYSERDA Initial Comments at 10–12.

[751] Louisiana Commission Reply Comments at 8 (citing Corrected General Order Docket No R–30021 (LPSC 3/12/2012)).

[752] APPA Initial Comments at 26, 36; TANC Initial Comments at 10.

[753] Exelon Initial Comments at 4, 7–8; Indicated PJM TOs Initial Comments at 10; Industrial Customers Initial Comments at 18; Louisiana Commission Reply Comments at 13; Mississippi Commission Initial Comments at 12; Nebraska Commission Initial Comments at 3–4; NRECA Initial Comments at 27–28; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; Omaha Public Power Initial Comments at 3–4; PJM Initial Comments at 5, 58–62; US Chamber of Commerce Initial Comments at 5–6; Utah Commission Initial Comments at 13.

[754] Indicated PJM TOs Initial Comments at 10.

[755] Mississippi Commission Initial Comments at 12; *see also* Louisiana Commission Reply Comments at 13 (citing Mississippi Commission Initial Comments at 12).

[756] NRECA Initial Comments at 27–28.

[757] PJM Market Monitor Initial Comments at 3.

[758] US Chamber of Commerce Initial Comments at 6.

[759] Nebraska Commission Initial Comments at 3.

[760] Industrial Customers Initial Comments at 18.

[761] Industrial Customers Initial Comments at 16–19 (referencing NYISO and the Eastern Interconnection Planning Collaborative planning processes).

[762] Ohio Consumers Initial Comments at 20.

[763] Nebraska Commission Initial Comments at 3–4; NRG Initial Comments at 6–9, 14; Omaha Public Power Initial Comments at 3–4.

[764] NRG Initial Comments at 6–9, 14.

[765] Utah Commission Initial Comments at 13.

[766] Exelon Initial Comments at 4, 7–8; PJM Initial Comments at 5, 58–62.

[767] Exelon Initial Comments at 4, 7–8.

[768] PJM Initial Comments at 59–62 (citing *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources,* Notice of Technical Conference, Docket No. AD05–3–000, at 1 (issued Feb. 16, 2005)).

[769] ACEG Initial Comments at 6–7, 24; CARE Coalition Initial Comments at 40–41; Interwest Initial Comments at 5; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 19–20; PIOs Initial Comments at 15; SEIA Initial Comments at 6.

consider up to a 40-year transmission planning horizon to match the expected life of most transmission assets.[770] CARE Coalition argues that a 40-year transmission planning horizon would be consistent with standard practice in economics and public policy of evaluating benefits over the life of the asset, and that the long lead time to develop transmission facilities justifies a longer planning horizon.[771]

iv. Opposition to Requests for a Different Transmission Planning Horizon

333. Several commenters dispute claims that a 20-year transmission planning horizon introduces risks from uncertainty and that a shorter planning horizon is more appropriate.[772] Southeast PIOs claim that the risk of unaddressed transmission needs grows over time because of long lead times needed for transmission development, and that SERTP's 10-year transmission planning horizon prevented Georgia Power from using that process to plan for its long-term North Georgia Reliability & Resilience Plan and its goal to integrate 6,000 MW of renewable resources by 2035.[773] Southeast PIOs assert that a longer transmission planning horizon will put future transmission needs on the radar for transmission planners and, if updated frequently, allow transmission providers to select transmission facilities conditional on subsequent transmission planning cycles, which affords planners flexibility to determine the need for the facility and whether there are more cost-effective alternatives.[774] ACORE notes that the NOPR addresses the uncertainty about the future by requiring the use of multiple Long-Term Scenarios that are revised every three years.[775]

334. Several commenters state that the transmission planning horizon should not extend beyond 20 years to avoid overly speculative long-term forecasts.[776] Entergy asserts that looking beyond 20 years would increase the likelihood of errors, risk billions of dollars in investments that may prove to be misguided, and amplify the risk of planning a transmission system that poorly aligns with actual future needs.[777] Illinois Commission states that a transmission planning horizon longer than 20 years would make it difficult to accurately predict the factors relevant to transmission planning.[778] Clean Energy Buyers propose that transmission providers seeking to adopt a transmission planning horizon beyond 20 years should be required to demonstrate the justness and reasonableness of that transmission planning horizon.[779]

335. Certain TDUs and Louisiana Commission oppose a 40-year transmission planning horizon.[780] Certain TDUs emphasize that, as evidenced by the Michigan Thumb Loop transmission project, assumptions such as the resource mix can change in as few as seven years.[781] Louisiana Commission argues that longer periods, such as the 40-year transmission planning horizon proposed by some commenters, will greatly increase the risk for errors and wasted investments. According to Louisiana Commission, transmission planning horizons should neither exceed the availability of reasonable data and assumptions nor create unnecessary risks that ratepayers will be required to fund transmission facilities that do not deliver expected benefits.[782]

v. Meaning and Scope of Transmission Planning Horizon

336. Several commenters request that the Commission define the 20-year transmission planning horizon as a simple 20-year period, and not a 20-year period starting from the estimated in-service date of the transmission facilities, which would result in forecasting transmission needs beyond 20 years.[783] Kentucky Commission Chair Chandler states that the usefulness of Long-Term Regional Transmission Planning and measuring benefits 20 years after a transmission project's in-service date will decrease if each project's relative benefits cannot be adequately measured and identified.[784] PPL argues that tying the transmission planning horizon to the study date rather than the solution in-service date will facilitate a more realistic, certain, and simple transmission planning process and reduce the need for additional analysis.[785] US Chamber of Commerce adds that beginning at the in-service date of the transmission facilities would extend the effective transmission planning horizon to 25–30 years, thereby further increasing the uncertainty of Long-Term Regional Transmission Planning; thus, US Chamber of Commerce argues the Commission should use the 20-year transmission planning horizon as a ceiling, rather than a floor, consistent with the far end of most state planning horizons, which would protect transmission planners from being forced to plan beyond the requirements of applicable state law.[786]

337. Policy Integrity requests that the Commission clarify the details of the 20-year time horizon, stating that it is unclear whether the Commission intended the 20-year time horizon for Long-Term Regional Transmission Planning to be tied to construction commencing in year 20.[787] ISO–NE and Policy Integrity seek clarification that, if the Commission requires that transmission providers must study what is needed over the next 20 years, transmission providers are not precluded from evaluating what needs to be built in the short and medium terms.[788] Industrial Customers assert that the proposed 20-year transmission planning horizon is unclear because some commenters interpret the Commission's proposal as requiring a 20-year transmission planning horizon for Long-Term Regional Transmission Planning,[789] while others argue it requires a 20-year transmission planning horizon in existing regional transmission planning processes.[790]

338. Several commenters support a 20-year transmission planning horizon if Long-Term Scenarios are used to inform the development of transmission

[770] ACEG Initial Comments at 6, 24.

[771] CARE Coalition Initial Comments at 40–41.

[772] ACORE Reply Comments at 5 (citing EPSA Initial Comments at 7; ITC Initial Comments at 9; Mississippi Commission Initial Comments at 12; PJM Initial Comments at 58–62); Concerned Scientists Reply Comments at 18–19; PJM Initial Comments at 58–62; Southeast PIOs Reply Comments at 23–25 (citing Dominion Initial Comments at 19; Southern Initial Comments at 19, 32–33).

[773] Southeast PIOs Reply Comments at 24 (citing Southeast PIOs Initial Comments at 27–28).

[774] *Id.* at 23–25.

[775] ACORE Reply Comments at 5.

[776] Arizona Commission Initial Comments at 3–4; California Commission Initial Comments at 11–13; Entergy Initial Comments at 9–11; Georgia Commission Initial Comments at 2–3; Pennsylvania Commission Initial Comments at 5; US Chamber of Commerce Initial Comments at 4, 6.

[777] Entergy Initial Comments at 9–11.

[778] Illinois Commission Initial Comments at 6.

[779] Clean Energy Buyers Initial Comments at 12–13.

[780] Certain TDUs Reply Comments at 3–6 (citing ACEG Initial Comments at 24); Louisiana Commission Reply Comments at 8.

[781] Certain TDUs Reply Comments at 3–6.

[782] Louisiana Commission Reply Comments at 8.

[783] Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12–13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

[784] Kentucky Commission Chair Chandler Reply Comments at 2.

[785] PPL Initial Comments at 6.

[786] US Chamber of Commerce Initial Comments at 6.

[787] Policy Integrity Initial Comments at 5.

[788] ISO–NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

[789] Industrial Customers Reply Comments at 5–6 (citing NARUC Initial Comments at 5).

[790] Industrial Customers Reply Comments at 5–6 (citing California Commission Initial Comments at 11).

facilities but not used to select transmission facilities or to dictate construction.[791] TANC does not believe that a 20-year transmission planning horizon should be used for local transmission planning processes or selection.[792] Nebraska Commission states that using a 20-year transmission planning horizon for only research, study, and projections will avoid speculation, increased costs, and unjust and unreasonable rates.[793] NRECA asserts that using a 20-year transmission planning horizon in Long-Term Regional Transmission Planning to select transmission projects will not produce the granularity and certainty needed to assign costs to beneficiaries.[794] Similarly, Ohio Consumers argue that too little is known about the location of future loads and resources and the direction of power flows over 20 years to use a 20-year transmission planning horizon for cost allocation purposes.[795] NRG argues that use of a 20-year transmission planning horizon to allocate costs will lead to unjust and unreasonable outcomes, and instead, a 10-year transmission planning horizon is appropriate.[796] New England Systems state that the Commission should adjust the NOPR's focus on transmission planning horizons toward an evolutionary and evidence-based transmission planning process aimed at mitigating avoidable costs for operating generation out of economic merit order and at improving the utilization of renewable resources that experience curtailment due to congestion.[797]

339. Some commenters support a 20-year transmission planning horizon only if the latter portion of the planning horizon is not used to direct the development of transmission facilities.[798] SERTP Sponsors state that the Commission should not require that regional transmission expansion be based on transmission planning horizons that are incompatible with the planning horizons used for integrated resource planning or supply-side resource plan development, or that involve a degree of speculation that the states comprising a transmission planning region are not willing to accept.[799] SPP Market Monitor contends that if the Commission requires all RTOs/ISOs to perform a 20-year study, the final order should also provide guidance on how information determined in that long-term study will be used. SPP Market Monitor supports a secondary, shorter-term transmission planning horizon of 10 years that could be based on the results of the longer-term 20-year studies.[800]

340. Shell suggests that the 20-year transmission planning horizon include a developmental ''Actionable Period'' for the first 10 years, during which developers may be willing to invest in generation projects, or the RTOs/ISOs or utilities may be willing to commit to and authorize the construction of new transmission. Shell proposes that there would be an ''Indicative Period'' for the following 10 years, which would be used to drive the Actionable Period so that the Commission establishes a process that converges and integrates short, medium, and long-term planning. Shell asserts that its proposal could foster more comprehensive and efficient Long-Term Regional Transmission Planning and inform existing regional transmission planning processes.[801] To remove speculative assumptions from Long-Term Regional Transmission Planning, Arizona Commission similarly suggests that the Commission divide the 20-year transmission planning horizon into two equal parts: a ''more certain'' forecast and a ''flexible'' forecast.[802] Likewise, APS recommends that the Commission adopt a 20-year transmission planning horizon for ''potential projects'' and a 10-year planning horizon for ''planned projects'' to provide greater regional flexibility.[803]

341. Kansas Commission, Mississippi Commission, and NRECA state that the results of Long-Term Regional Transmission Planning should be considered informational only.[804] Kansas Commission requests that the Commission establish solid evidentiary and policy bases to support a 20-year transmission planning horizon before imposing such a requirement.[805] Mississippi Commission believes that transmission construction decisions should use a 10-year transmission planning horizon.[806]

342. Some commenters rebut arguments that Long-Term Regional Transmission Planning should be performed for informational purposes only.[807] ACEG contends that adopting the proposed transmission planning methods is essential to accomplishing the Commission's responsibilities and that less stringent requirements have not led to much-needed development of high-capacity transmission throughout the country. ACEG further states that providing informational reports will do little to remedy undue discrimination and achieve actual transmission plans.[808] DC and MD Offices of People's Counsel state that the potential benefits to ratepayers and other stakeholders of a 20-year transmission planning horizon is significantly diminished if transmission planning is simply an academic exercise, without actual impact on future transmission development.[809] SEIA argues that the Commission should mandate that scenarios developed under the final order be used in transmission planning rather than for informational purposes only or contingent on the approval of state regulators.[810]

343. Business Council for Sustainable Energy states that transmission planning should consider the length of time that it takes for transmission assets to be built and the estimated useful life of those facilities.[811] California Municipal Utilities argue, and TANC concurs, that any lengthening of the transmission planning horizon must be accompanied by consumer protections that guard against speculative siting of generation and a rigorous re-evaluation of planning assumptions and other relevant factors, such as commercial viability of transmission projects and the associated resources.[812]

c. Commission Determination

344. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop

[791] NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; *see also* Dominion Reply Comments at 4–5 (citing NARUC Initial Comments at 5); PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

[792] TANC Initial Comments at 10.

[793] Nebraska Commission Initial Comments at 3.

[794] NRECA Initial Comments at 23–24 (citing GDS Assocs., Inc., Report, at 10 (Aug. 17, 2022)).

[795] Ohio Consumers Initial Comments at 1, 20.

[796] NRG Initial Comments at 6–9, 14.

[797] New England Systems Initial Comments at 21–22.

[798] APS Initial Comments at 3–4; Kansas Commission Initial Comments at 13–14; Maryland Energy Administration Initial Comments at 3; SERTP Sponsors Initial Comments at 20; Shell Initial Comments at 21; SPP Market Monitor Initial Comments at 5–6.

[799] SERTP Sponsors Initial Comments at 20.

[800] SPP Market Monitor Initial Comments at 5–6.

[801] Shell Initial Comments at 19–23.

[802] Arizona Commission Initial Comments at 3–4.

[803] APS Initial Comments at 3–4.

[804] Kansas Commission Initial Comments at 13–14; Mississippi Commission Reply Comments at 6; NRECA Initial Comments at 23.

[805] Kansas Commission Initial Comments at 13.

[806] Mississippi Commission Reply Comments at 6.

[807] ACEG Reply Comments at 10; DC and MD Offices of People's Counsel Reply Comments at 5; SEIA Reply Comments at 2.

[808] ACEG Reply Comments at 10.

[809] DC and MD Offices of People's Counsel Reply Comments at 5.

[810] SEIA Reply Comments at 2.

[811] Business Council for Sustainable Energy Initial Comments at 4.

[812] California Municipal Utilities Initial Comments at 3; TANC Initial Comments at 10.

Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. We further clarify that using a transmission planning horizon of no less than 20 years means that transmission providers must develop Long-Term Scenarios to identify Long-Term Transmission Needs that will materialize in the 20 years or more following the commencement of the Long-Term Regional Transmission Planning cycle.

345. In requiring a transmission planning horizon of not less than 20 years, we strike a balance. On the one hand, a 20-year transmission planning horizon extends far enough into the future that transmission providers can proactively identify Long-Term Transmission Needs that could be met with more efficient or cost-effective Long-Term Regional Transmission Facilities; in contrast, as discussed below, a transmission planning horizon less than 20 years may limit transmission providers' ability to adequately plan for Long-Term Transmission Needs. Specifically, as described in the NOPR, a 20-year transmission planning horizon allows for more time between when a transmission facility is identified to meet a future transmission need, and when the transmission need materializes, allowing for sufficient time to identify, plan, obtain siting and permitting approval for, and construct Long-Term Regional Transmission Facilities. Moreover, as some commenters observe, several transmission providers, including MISO, SPP, and NYISO, already use a 20-year transmission planning horizon. On the other hand, based on the record before us, we find that there may be sufficient uncertainty with regard to system conditions and transmission needs beyond a 20-year horizon such that it may be challenging for transmission providers to forecast Long-Term Transmission Needs across that time period, especially for those transmission providers that do not presently conduct, and thus do not have experience with, long-term regional transmission planning. Accordingly, we decline to adopt a requirement to use a transmission planning horizon that exceeds 20 years. However, this does not preclude transmission providers from proposing to use a transmission planning horizon of more than 20 years.

346. We clarify that transmission providers must plan for the entire duration of the 20-year transmission planning horizon. Specifically, transmission providers must, among other requirements established in this final order, develop and use Long-Term Scenarios to identify Long-Term Transmission Needs occurring in any period of the 20-year transmission planning horizon and to evaluate potential transmission solutions to those needs.

347. Certain commenters either misstate aspects of the proposed 20-year transmission planning horizon or request clarification regarding the horizon.[813] We specify that the transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date. The transmission planning horizon is not tied to the in-service date of any identified transmission solution; rather, potential transmission solutions are identified after identifying Long-Term Transmission Needs that manifest during the 20-year transmission planning horizon.

348. We disagree with commenters that assert that a 20-year transmission planning horizon could result in Long-Term Regional Transmission Planning based on speculative transmission needs[814] or, relatedly, that a 20-year transmission planning horizon is only appropriate if Long-Term Scenarios are not used to select Long-Term Regional Transmission Facilities.[815] We find these assertions to be unfounded. In fact, the Long-Term Regional Transmission Planning requirements adopted in this final order are designed to avoid over-building transmission in response to speculative transmission needs through a series of tools and safeguards, discussed at length above.[816] To highlight just one of these safeguards, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, we require transmission providers to reevaluate certain previously selected Long-Term Regional Transmission Facilities in some circumstances to confirm that the Long-Term Regional Transmission Facility continues to meet the transmission providers' selection criteria. This reevaluation process will help ensure that the continued selection of Long-Term Regional Transmission Facilities is based on the use of updated information regarding the existence of a Long-Term Transmission Need and the benefits that transmission providers expect a Long-Term Regional Transmission Facility to provide.

349. We disagree with commenters that assert that the Commission should adopt a shorter transmission planning horizon.[817] A transmission planning horizon of less than 20 years would fail to sufficiently capture Long-Term Transmission Needs given that at least some of the drivers of such needs extend up to 20 years into the future (*e.g.,* many state laws include requirements to be met 15 to 20 years in the future). Additionally, a shorter minimum transmission planning horizon may not allow for sufficient time to develop Long-Term Regional Transmission Facilities with long lead-time requirements or to compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.

350. We disagree with commenters that assert requiring a 20-year transmission planning horizon is incompatible with planning horizons used with state integrated resource planning.[818] In addition to the discussions in the Overall Need for Reform and Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning sections regarding state integrated resource planning, we note that regardless of the planning horizon used in a state integrated resource planning process, the results of that process can be incorporated into Long-Term Regional Transmission Planning to identify Long-Term Transmission Needs. In fact, as explained in State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three) section below, integrated resource plans are part of the Categories of Factors and thus, transmission providers must incorporate information on the load-serving entities' projected loads and resources over the planning horizon. The fact that a state integrated resource plan does not extend out a full 20 years—or extends further

[813] Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12–13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

[814] *E.g.,* TANC Initial Comments at 10.

[815] NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; *see also* PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

[816] *See supra* Participation in Long-Term Regional Transmission Planning section.

[817] Exelon Initial Comments at 4, 7–8; Industrial Customers Initial Comments at 18; Mississippi Commission Initial Comments at 34; Nebraska Commission Initial Comments at 3–4; NRECA Initial Comments at 27–28; NRG Initial Comments at 6–9, 14; Omaha Public Power Initial Comments at 3–4; PJM Initial Comments at 5, 58–62; US Chamber of Commerce Initial Comments at 6; Utah Commission Initial Comments at 13.

[818] SERTP Sponsors Initial Comments at 21.

into the future—does not change the obligation for transmission providers to incorporate the information that is available over the 20-year transmission planning horizon.

351. In response to ISO–NE, and Policy Integrity,[819] the 20-year transmission planning horizon is distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from the estimated in-service date, as discussed in the Required Benefits section.

2. Frequency of Long-Term Scenario Revisions

a. NOPR Proposal

352. In the NOPR, the Commission proposed to require each transmission provider to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in the previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors. The Commission also proposed to require that the development of Long-Term Scenarios be completed within three years, before the next three-year assessment commences.[820]

353. The Commission preliminarily found that a three-year frequency requirement balances the need of transmission providers to reassess changes in the resource mix and demand, as technology, markets, and policies have the potential to rapidly change, against the burden of developing Long-Term Scenarios that can take a year or longer to produce. The Commission stated that this three-year frequency requirement would allow transmission providers to identify new transmission needs driven by changes in the resource mix and demand during the interim years of the transmission planning period, and update previously identified transmission needs, if warranted.[821]

b. Comments

i. Support for Frequency of Long-Term Scenario Revisions

354. Many commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.[822] Arizona Commission and Interwest state that the proposed three-year process aligns with their existing regional transmission planning processes.[823] Several commenters assert that this proposal allows for Long-Term Scenarios to remain accurate and account for material technological, political, environmental, and operational developments in the energy industry,[824] with some commenters indicating that past experience demonstrates that the energy industry is rapidly changing.[825] For example, PIOs share that MISO recently recognized assumptions in its MISO Transmission Expansion Plan did not capture the rate of change for the region's fuel mix.[826]

355. Pennsylvania Commission states that routine reviews could update information and data, justify modifications to transmission plans, and reduce the risk of uneconomic transmission investments.[827] ELCON notes that the proposed three-year reassessment provides the opportunity to consult recent data and update the probability of each scenario, which will produce better outcomes in the transmission planning process.[828] Joint Consumer Advocates state that long-term transmission plans must be revisited regularly and with sufficient frequency to ensure that they remain accurate and account for material developments.[829] AEE states that triennial updates will provide a suitable amount of time for stakeholders to complete comprehensive studies while also ensuring that scenarios do not become stale as advanced energy technology deployment scales more rapidly and policy changes disrupt existing assumptions.[830]

356. Louisiana Commission avers that the proposed three-year reassessment will prevent transmission providers from ignoring changes that might better reflect future assumptions.[831] PIOs state that a three-year update will also help address issues that could occur if a transmission provider is too aggressive or conservative when defining scenarios.[832] DC and MD Offices of People's Counsel recommend that plans be updated every three years.[833]

357. Entergy and Interwest state that a three-year reassessment cycle balances the need for recent data and the time and resources needed to develop the updates.[834] LADWP states that a rolling near-term planning horizon provides the long-term transmission planning process with up-to-date information without being too frequent.[835] New Jersey Commission notes that reassessments more frequent than every three years would be overly burdensome.[836] Similarly, Nebraska Commission states that a frequency shorter than every three years would require almost constant updates from transmission providers, which would drive up costs, while a frequency longer than three to five years could risk the underlying information becoming stale between revisions.[837]

358. Certain TDUs suggest that the Commission address concerns that a three-year review period would put significant strain on transmission provider resources by clarifying that three-year assessments would review the key drivers and assumptions behind

[819] ISO–NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

[820] NOPR, 179 FERC ¶ 61,028 at P 97.

[821] NOPR, 179 FERC ¶ 61,208 at P 99.

[822] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8–9; AEP Initial Comments at 5, 8, 13–14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6–8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5–6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

[823] Arizona Commission Initial Comments at 3; Interwest Initial Comments at 6–8.

[824] Advanced Energy Buyers Initial Comments at 7; California Water Initial Comments at 15; ELCON Initial Comments at 11; Joint Consumer Advocates at 8; PIOs Initial Comments at 17; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11.

[825] Advanced Energy Buyers Initial Comments at 7; ELCON Initial Comments at 11.

[826] PIOs Initial Comments at 16–17 (stating that MISO's prediction for changes in its fuel mix 15 years out in the MISO Transmission Expansion Plan 2020 Report had already materialized before that final report was published).

[827] Pennsylvania Commission Initial Comments at 5.

[828] ELCON Initial Comments at 11.

[829] Joint Consumer Advocates Initial Comments at 8.

[830] AEE Initial Comments at 8–9.

[831] Louisiana Commission Reply Comments at 9.

[832] PIOs Initial Comments at 17.

[833] DC and MD Offices of People's Counsel Reply Comments at 2.

[834] Entergy Initial Comments at 11; Interwest Initial Comments at 6.

[835] LADWP Initial Comments at 3.

[836] New Jersey Commission Initial Comments at 11.

[837] Nebraska Commission Initial Comments at 4.

a transmission plan with updates as needed for material changes rather than a rerun of the full transmission planning process. In addition, Certain TDUs state that a three-year reassessment of initial transmission plans would result in more transparency and consideration of alternatives in the transmission planning process.[838] In contrast, PJM requests that the Commission clarify that Long-Term Scenarios would be completely updated with new data, updated factors, and the best information available at least every three years, not merely partially reassessed. PJM also requests that the Commission clarify that scenario evaluations will not overlap, as re-runs are expensive, and a predictable three-year clock will make the process run smoothly.[839]

359. AEP requests that the Commission require all transmission planning regions to continuously follow the same, consistent three-year transmission planning cycles to align future efforts and ease burdens on transmission providers and developers operating in multiple transmission planning regions and to promote better coordination among regions concerning potential interregional transmission solutions.[840]

360. Southeast PIOs support the NOPR proposal to require transmission providers to reassess and revise Long-Term Scenarios every three years, arguing that it would synchronize with existing state processes and ensure that long-term regional transmission plans remain an up-to-date resource for state planning.[841] Similarly, Certain TDUs argue that a five-year transmission planning cycle is too long and that a three-year transmission planning cycle would be more likely to account for unforeseen changes, helping to prevent inefficient transmission development and balance planning for future needs with the need to quickly identify material changes to planning assumptions.[842]

ii. Concerns About Frequency of Long-Term Scenario Revisions

361. Some commenters urge the Commission to provide flexibility for transmission providers to determine the frequency at which they must develop Long-Term Scenarios by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.[843] EEI requests that the Commission allow transmission providers in each transmission planning region to initiate a new Long-Term Scenario process in lieu of a refresh of old Long-Term Scenarios.[844] California Commission and Omaha Public Power argue that requiring transmission providers to reassess and revise Long-Term Scenarios at least every three years will create a significant compliance burden without improving planning outcomes, such as forecast accuracy.[845]

362. MISO TOs argue that flexibility is warranted because MISO is already implementing Long-Term Regional Transmission Planning, as well as reassessing its data as needed.[846] MISO states that the NOPR proposal is overly prescriptive, may not reflect stakeholder and regional needs, and could result in a compliance exercise without the prospect of transmission expansion.[847] NESCOE and OMS suggest that the Commission require transmission providers to reassess Long-Term Scenarios at regular intervals but leave the timing of that reassessment to the transmission planning region.[848] MISO also recommends that the Commission allow transmission providers to reuse Long-Term Scenarios as long as they update the relevant input data to reflect the latest available information.[849]

363. Duke asserts that the Commission should allow transmission planning regions to propose their own cycles to reassess and revise Long-Term Scenarios to meet the needs of the region, keep pace with markets and policies across the country, and align their processes with state integrated resource planning processes.[850] Similarly, WIRES requests a variance to the proposed three-year scenario reassessment requirement because three years may be too short and could potentially be disruptive or increase costs. WIRES further asks that the Commission clarify that transmission providers are not required to reassess previously approved transmission projects as part of their triennial review process.[851]

364. Pacific Northwest State Agencies state that the Commission should set three years as a minimum and provide transmission planning regions with the flexibility to work with states to determine the appropriate schedule for developing Long-Term Scenarios.[852] Similarly, Vermont State Entities and Pennsylvania Commission argue that transmission planning regions should have the flexibility to conduct reassessments at intervals shorter than every three years.[853]

365. NYISO recommends that the final order should allow transmission planning regions to modify or add to their Long-Term Scenarios to account for changes that would significantly affect their analysis when they occur instead of waiting for the next transmission planning cycle. NYISO further requests that the Commission clarify that, if a transmission planning region requires more than three years to complete a given transmission planning cycle, it may extend the three-year time period. In addition, NYISO requests that the Commission permit transmission providers in each transmission planning region to commence the next Long-Term Regional Transmission Planning cycle using current information even if the prior transmission planning cycle is running in parallel. NYISO adds that the Commission should allow transmission planning regions to use their existing Long-Term Scenarios for the duration of a Long-Term Regional Transmission Planning cycle, even if it runs beyond three years, to avoid stopping and re-starting that cycle due to changes in circumstances.[854]

366. Some commenters raise concerns that the proposal to require development of Long-Term Scenarios at least every three years may create overlapping planning assessments and suggest ways to avoid that situation.[855] ISO–NE states that the timeframe for Long-Term Regional Transmission Planning should account for all the elements of the process, such as implementing the process for selecting

[838] Certain TDUs Reply Comments at 7.

[839] PJM Initial Comments at 6, 63–64.

[840] AEP Initial Comments at 5, 8, 13–14; AEP Reply Comments at 5.

[841] Southeast PIOs Reply Comments at 25.

[842] Certain TDUs Reply Comments at 5–6.

[843] Ameren Initial Comments at 12–13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO–NE Initial Comments at 24; MISO Initial Comments at 28–29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6–7; NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

[844] EEI Initial Comments at 12.

[845] California Commission Initial Comments at 16; Omaha Public Power Initial Comments at 3.

[846] MISO TOs Initial Comments at 17.

[847] MISO Initial Comments at 28.

[848] NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5.

[849] MISO Initial Comments at 29.

[850] Duke Initial Comments at 12.

[851] WIRES Initial Comments at 7.

[852] Pacific Northwest State Agencies Initial Comments at 15.

[853] Pennsylvania Commission Initial Comments at 5; Vermont State Entities Initial Comments at 5.

[854] NYISO Initial Comments at 19.

[855] Eversource Initial Comments at 15; ISO–NE Initial Comments at 24; NESCOE Initial Comments at 26; PJM Initial Comments at 63.

transmission solutions, before the next long-term study begins. ISO–NE indicates that this will allow subsequent Long-Term Regional Transmission Planning studies to account for the outcomes of the preceding transmission planning cycle and avoid unnecessary study overlap between cycles.[856]

367. Eversource suggests that the Commission require completion of project selection before the development of the next set of Long-Term Scenarios, arguing that it would undermine the project selection process if the current three-year Long-Term Scenario cycle fails to include selected transmission facilities from the prior three-year cycle.[857]

368. Similarly, NESCOE is concerned that the three-year Long-Term Scenario cycle requirement is inflexible and could interfere with existing procedures in New England. NESCOE states that ISO–NE's longer-term transmission planning process requires that a planning process be concluded before a new one can begin, and that a request for a longer-term transmission study may be submitted to ISO–NE no earlier than six months after the conclusion of the prior study.[858]

369. Some commenters argue that requiring transmission providers to reassess and revise their Long-Term Scenarios every three years may be too frequent and costly, asserting that between every three and five years may be more appropriate.[859] ITC avers that a three-year transmission planning cycle for Long-Term Regional Transmission Planning would exceed the capabilities of the transmission providers administering the process.[860] Likewise, NRECA asserts that developing multiple Long-Term Scenarios and updating them every three years will require significant time and resources, as well as substantial changes in transmission planning throughout the country. NRECA asserts that existing power supply and transmission planning models employ different assumptions that cannot be used to prepare 20-year Long-Term Scenarios, much less update them every three years.[861]

[856] ISO–NE Initial Comments at 24.

[857] Eversource Initial Comments at 15.

[858] NESCOE Initial Comments at 26.

[859] ACEG Initial Comments at 7, 25; Breakthrough Energy Initial Comments at 12–13; EEI Initial Comments at 12; Indicated PJM TOs Initial Comments at 11–12; ITC Initial Comments at 5, 9–11; Pine Gate Initial Comments at 19–20.

[860] ITC Initial Comments at 10.

[861] NRECA Initial Comments at 23 (citing GDS Assocs., Report, at 8–10 (Aug. 17, 2022)).

iii. Support for Different Frequency of Long-Term Scenario Revisions

370. Western PIOs support mandating a two-year timeframe for revision, as three years may be too long and therefore may miss important updated data inputs.[862]

371. Shell argues that the Commission should require transmission providers to reassess and revise their Long-Term Scenarios every five years, asserting that the proposal to use three years could create too much uncertainty and delay the development of renewable generation being developed to comply with state climate objectives and resource adequacy requirements in forward-looking capacity markets.[863] Indicated PJM TOs argue that three years may be insufficient to perform relevant studies and recommend that the Commission provide transmission providers with the flexibility to adopt four- or five-year transmission planning cycles.[864]

372. Exelon argues that a three-year transmission planning cycle is too short, as it is unlikely that transmission needs will surface within three years, and that conducting a study so soon could create uncertainty that recently selected transmission projects will be revisited. Exelon instead recommends that the final order adopt a five-year transmission planning cycle requirement with a provision that requires transmission providers to initiate a new cycle sooner, with good reason, to better align with the time needed to permit and construct new transmission infrastructure.[865]

373. Similarly, PPL argues that a five-year transmission planning cycle will allow sufficient time for one transmission planning cycle to be completed before the subsequent cycle commences.[866] Pine Gate states that a five-year transmission planning cycle is warranted given the size and complexity of transmission planning regions and the time needed to receive and incorporate stakeholder feedback and to achieve consensus on cost allocation. Pine Gate further notes that a five-year transmission planning cycle would more closely align the results of Long-Term Regional Transmission Planning with the time horizons for reliability planning and other transmission planning processes.[867]

374. SPP argues in favor of the update procedures in its current transmission planning processes rather than the three-year schedule for updating Long-Term Scenarios proposed in the NOPR. SPP states that it performs a 20-year assessment that incorporates Long-Term Scenarios at least once every five years and that, on an annual basis, SPP assesses data inputs and factors incorporated into the assessment.[868]

[862] Western PIOs Initial Comments at 30.

[863] Shell Initial Comments at 18–19.

[864] Indicated PJM TOs Initial Comments at 11–12.

[865] Exelon Initial Comments at 9.

[866] PPL Initial Comments at 6.

[867] Pine Gate Initial Comments at 20–21.

iv. Miscellaneous Comments

375. Several commenters state that the Commission should regularly review transmission planning processes and assumptions to account for new developments.[869] Pattern Energy states that the best way to make 20-year transmission plans useful is for their outputs to be fed into near-term (*i.e.,* five-to-seven-year horizon) transmission planning activities.[870]

376. ELCON recommends that the Commission hold a technical conference after the first three-year reassessment period for Long-Term Scenarios to allow transmission providers to offer their experiences with and best practices for Long-Term Regional Transmission Planning.[871]

c. Commission Determination

377. We modify the NOPR proposal to require transmission providers in each transmission planning region to reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years. In implementing this requirement, transmission providers in each transmission planning region must reassess whether the data inputs and factors incorporated in previously developed Long-Term Scenarios need to be updated and then revise those Long-Term Scenarios, as needed, to reflect updated data inputs and factors. At the outset of a Long-Term Regional Transmission Planning cycle, transmission providers may develop the new Long-Term Scenarios either by crafting entirely new Long-Term Scenarios, or by updating the data inputs and factors of previously developed Long-Term Scenarios.

378. To assist transmission providers in implementing the requirement to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, we clarify that the process, which begins with the development of Long-Term Scenarios using best available data inputs, and

[868] SPP Initial Comments at 5–6.

[869] Clean Energy Buyers Initial Comments at 13; SREA Reply Comments at 26–27.

[870] Pattern Energy Initial Comments at 22.

[871] ELCON Initial Comments at 11.

proceeds to identifying Long-Term Transmission Needs, measuring the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluating and deciding whether to select Long-Term Regional Transmission Facilities (collectively, the Long-Term Regional Transmission Planning cycle),[872] must conclude at a date that is no later than five years after the date that it began.

379. While we find that the record supports a five-year interval before new Long-Term Scenarios must be developed, we also conclude that transmission providers should not need the full five-year period to reach the point in Long-Term Regional Transmission Planning at which they decide whether to select Long-Term Regional Transmission Facilities that they have evaluated. Accordingly, we require transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle and determine whether to select Long-Term Regional Transmission Facilities no later than three years from the date when the Long-Term Regional Transmission Planning cycle began.[873] Specifically, we find the record demonstrates that three years provides sufficient time for transmission providers to develop Long-Term Scenarios, identify Long-Term Transmission Needs, measure the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluate and decide whether to select Long-Term Regional Transmission Facilities.[874] At the same time, we are persuaded by commenters' concerns that requiring the Long-Term Regional Transmission Planning cycle to repeat at three-year intervals could be administratively burdensome, and that the benefit of updating Long-Term Scenarios every three years may not outweigh those additional burdens.[875] We therefore find that requiring selection decisions to occur within three years of commencing a Long-Term Regional Transmission Planning cycle, while allowing as long as five years between the commencement of each planning cycle, strikes an appropriate balance by ensuring timely identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities, while balancing the administrative burden associated with updating the Long-Term Scenarios that form the basis for Long-Term Regional Transmission Planning during each planning cycle.[876]

380. We find that requiring transmission providers to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years is necessary to ensure that the Long-Term Scenarios accurately reflect factors that may change over the five-year time span, such as changes in technology, load forecasts, or Federal, federally-recognized Tribal, state, or local laws. Furthermore, regular scenario reassessment and revision may also address some of the uncertainty associated with Long-Term Regional Transmission Planning over a 20-year transmission planning horizon that some commenters assert may result in under-building or over-building transmission facilities.[877] As discussed below in the Specificity of Data Inputs section, nothing in this final order prohibits transmission providers from updating the inputs used to inform Long-Term Scenarios during a Long-Term Regional Transmission Planning cycle.

381. As discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, transmission providers must designate a point in the evaluation process at which they will make a decision to either select or not select the relevant Long-Term Regional Transmission Facility (or portfolio of such Facilities). Further, we clarify that transmission providers must conclude a Long-Term Regional Transmission Planning cycle before developing Long-Term Scenarios at the beginning of the next Long-Term Regional Transmission Planning cycle. Given that, as we state directly above, nothing in this final order prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins, we further find that transmission providers must designate the point in time or action that concludes a Long-Term Regional Transmission Planning cycle. Such designation will ensure transparency regarding whether the transmission providers are engaging in the evaluation and selection of additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle.

382. Some commenters express concern that the proposal to reassess Long-Term Scenarios in concurrent Long-Term Regional Transmission Planning cycles would create uncertainty as to which cycle produced the controlling outcome and would burden stakeholders (*e.g.,* requiring them to provide input on the development of Long-Term Scenarios for the next Long-Term Regional Transmission Planning cycle while also requiring them to provide input on Long-Term Regional Transmission Facilities being considered for selection from the previous Long-Term Regional Transmission Planning cycle).[878] By providing for a period of up to two years between the date by which transmission

[872] The Long-Term Regional Transmission Planning cycle encompasses all components of Long-Term Regional Transmission Planning, including each of these foundational steps.

[873] To be clear, nothing in this final order prevents transmission providers from evaluating and selecting *additional* Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins. However, if Long-Term Regional Transmission Facilities are selected at year three of the Long-Term Regional Transmission Planning cycle, those same Long-Term Regional Transmission Facilities cannot be de-selected during the remainder of the current five-year planning cycle.

[874] *See* ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8–9; AEP Initial Comments at 5, 8, 13–14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6–8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5–6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

[875] *See* Ameren Initial Comments at 12–13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO–NE Initial Comments at 24; MISO Initial Comments at 28–29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6–7; NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

[876] Accordingly, we decline NYISO's request to clarify that the transmission provider may extend the transmission planning cycle. As explained, we find that three years provides sufficient time to complete the actions necessary to make selection decisions.

[877] Industrial Customers Initial Comments at 15–16, 19–21; NRECA Initial Comments at 18–19, 28; Vistra Initial Comments at 7.

[878] Eversource Initial Comments at 15; ISO–NE Initial Comments at 24; NESCOE Initial Comments at 26.

providers are required to make a decision to select or not select Long-Term Regional Transmission Facilities and the date by which the next Long-Term Regional Transmission Planning cycle must commence, and by clarifying that transmission providers must conclude one Long-Term Regional Transmission Planning cycle before another begins, this final order will appropriately minimize confusion regarding overlap between planning assessments. Specifically, this clarification will allow transmission providers to use in subsequent Long-Term Regional Transmission Planning cycles updated base or reference cases that include all Long-Term Regional Transmission Facilities that were selected in a previous Long-Term Regional Transmission Planning cycle, including those not yet in service. We find that including the selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles will improve the accuracy of Long-Term Regional Transmission Planning.

383. In response to WIRES's request,[879] we clarify that transmission providers need not routinely reevaluate selected Long-Term Regional Transmission Facilities. However, we note that, as discussed further in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities in certain specified circumstances.

384. Given that we are requiring transmission providers in each transmission planning region to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, thus establishing the maximum length of the Long-Term Regional Transmission Planning cycle, we affirm that to the extent that transmission providers believe that a shorter Long-Term Regional Transmission Planning cycle is appropriate for their transmission planning region and circumstances, they may propose on compliance to conduct Long-Term Regional Transmission Planning more frequently than every five years.

385. We find AEP's request to require all transmission planning regions to follow the same-length transmission planning cycles is beyond the scope of this proceeding.[880] In the NOPR, we proposed frequency requirements related to the Long-Term Regional Transmission Planning cycles but did not propose a requirement for transmission providers to align their regional transmission planning cycles with those of the transmission providers in neighboring transmission planning regions.

386. While we do not establish a technical conference after the first Long-Term Regional Transmission Planning cycle, as ELCON requests,[881] the Commission has discretion to conduct additional proceedings at a future date if it finds they are warranted.

3. Categories of Factors

a. Requirement To Incorporate Categories of Factors

i. NOPR Proposal

387. In the NOPR, the Commission proposed to require transmission providers to incorporate specific categories of factors in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[882] Specifically, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) Federal, state, and local laws and regulations that affect the future resource mix and demand;[883] (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[884] that affect the future resource mix and demand.[885]

388. The Commission preliminarily found that incorporating, at a minimum, these categories of factors in the development of Long-Term Scenarios is appropriate because these categories of factors affect the future resource mix and demand, and their incorporation in Long-Term Scenarios is therefore essential to identifying transmission needs driven by changes in the resource mix and demand through Long-Term Regional Transmission Planning.[886] To the extent that transmission providers in a transmission planning region would like to incorporate additional categories of factors in the development of Long-Term Scenarios, the Commission proposed to require that they demonstrate on compliance with any final order that the incorporation of more than the minimum categories is consistent with or superior to any final order in this proceeding.[887]

389. Also, as discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Processes section of the NOPR,[888] the Commission proposed to require that transmission providers consider in their Long-Term Regional Transmission Planning regional transmission facilities that address interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s). The Commission proposed to require that transmission providers incorporate the specific interconnection-related needs identified through that proposed reform, in addition to one or more factors that more generally characterize generator interconnection withdrawals, as a factor in the generator interconnection requests and withdrawals category of factors in their development of Long-Term Scenarios.[889]

390. The Commission explained that incorporation of the categories of factors set forth above in developing Long-Term Scenarios would help facilitate the identification of transmission needs driven by changes in the resource mix and demand, which the Commission preliminarily found was necessary to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates. The Commission explained that absent a requirement to incorporate these categories of factors in the development of Long-Term Scenarios, transmission providers may not incorporate known inputs that likely will affect the future resource mix and demand. Additionally, the Commission explained that transmission providers may not adequately identify transmission needs

879 WIRES Initial Comments at 7.

880 AEP Initial Comments at 5, 8, 14; AEP Reply Comments at 5.

881 ELCON Initial Comments at 11.

882 NOPR, 179 FERC ¶ 61,028 at PP 104–112.

883 *Id.* P 104 n.189. The Commission explained that "state or federal laws or regulations" meant "enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state, municipality, or at the federal level."

884 *Id.* P 104 n.195. The Commission explained that "goal" meant "any commitment or statement expressed in writing that is not a law or regulation."

885 *Id.* P 104.

886 *Id.* P 105.

887 *Id.*

888 *Id.* PP 166–174.

889 *Id.* P 107.

driven by changes in the resource mix and demand and evaluate the potential benefits of regional transmission facilities that may more efficiently or cost-effectively meet such needs. The Commission stated that, as an additional benefit, this requirement would provide clarity to transmission providers and stakeholders regarding which factors must be considered in scenario development.[890]

ii. Comments

(a) Requirement To Incorporate Categories of Factors

391. A number of commenters support the proposal to require transmission providers to incorporate in their development of Long-Term Scenarios the seven specific categories of factors identified in the NOPR.[891] Georgia Commission asserts that these categories of factors adequately capture the factors expected to drive changes in the resource mix and demand,[892] and APPA states that they reflect potential drivers of the need for new transmission.[893]

392. AEE asks that the Commission clarify that consideration of each factor is mandatory, arguing that failing to take into account any of the seven listed categories of factors would risk under-investment in regional transmission facilities, which could result in unjust and unreasonable rates.[894] Evergreen Action and Pine Gate assert that the Commission should require that the seven factors are ''incorporated'' instead of ''considered'' in order to make clear that incorporation is not optional.[895] Otherwise, Pine Gate states, transmission providers may ignore certain categories relevant and critical to identifying needed transmission infrastructure.[896]

393. DC and MD Offices of People's Counsel also urge the Commission to require that all seven factor categories listed in the NOPR be included in Long-Term Scenarios.[897] DC and MD Offices of People's Counsel and ACEG state that the flexibility proposed in the NOPR could give transmission providers the option of not considering the last four factor categories.[898] SEIA recommends that the Commission establish guidelines on the information used to determine factors in the last four factor categories to ensure some level of certainty in how they are reflected in Long-Term Scenarios.[899]

394. Clean Energy Buyers support the NOPR proposal, arguing that requiring uniform categories of factors across transmission planning regions could promote efficiency and interregional coordination.[900] Southeast PIOs argue that broader consideration of resource trends and other transmission drivers through comprehensive scenarios will inform the decision-making of state authorities tasked with approving transmission facilities.[901] Indicated US Senators and Representatives express general support for proactive transmission planning that considers a broad range of factors.[902]

395. MISO TOs, MISO, and OMS state that existing MISO processes already identify and consider the proposed categories of factors to develop scenarios for transmission planning.[903] MISO TOs further claim that there is no need to require that MISO consider additional factors.[904] OMS supports the NOPR's proposed requirements as to the minimum categories of factors and asserts that the categories of factors proposed in the NOPR are all included in MISO's existing transmission planning processes.[905]

396. Some commenters support the NOPR proposal because they note that it provides transmission providers with flexibility as to the specific factors they incorporate into their development of Long-Term Scenarios, as well as how they incorporate those factors.[906]

397. A few commenters support the NOPR proposal to allow transmission providers to incorporate additional categories of factors if they can demonstrate that doing so is consistent with or superior to the final order.[907] Specifically, AEE states that the Commission should clarify that transmission providers can propose to consider other categories of factors.[908]

398. Pattern Energy states that the Commission should provide examples of how the categories of factors and their associated sensitivities may be modeled to ensure that each Long-Term Scenario is useful for Long-Term Regional Transmission Planning. For example, Pattern Energy asks whether the different scenarios alter the various assumptions for each (or some) of the factors. Alternatively, Pattern Energy asks whether the assumptions remained fixed across scenarios and different scenarios are designed to evaluate different transmission solutions.[909]

(b) Requests for Flexibility

399. Some commenters argue that the Commission should give transmission providers more flexibility to determine the appropriate categories of factors or individual factors to include in their development of Long-Term Scenarios.[910] NESCOE contends that providing flexibility would be consistent with the Commission's approach in Order No. 1000, where it did not require the identification of transmission needs driven by any particular Public Policy Requirements.[911] PG&E argues that the Commission should allow transmission providers to experiment with how they define scenarios and factors to best reflect the policy and planning environments of their transmission

[890] *Id.* P 111.

[891] ACEG Initial Comments at 7; Advanced Energy Buyers Initial Comments at 5; AEE Initial Comments at 9–10; Breakthrough Energy Initial Comments at 14; Breakthrough Energy Supplemental Comments at 1; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10–11; Clean Energy Buyers Initial Comments at 14–15; ELCON Initial Comments at 12; Eversource Initial Comments at 16–17; Illinois Commission Initial Comments at 4–5; Kansas Commission Initial Comments at 14–15; Nevada Commission Initial Comments at 8; Northwest and Intermountain Initial Comments at 13; NRECA Initial Comments at 30; OMS Initial Comments at 6; Ørsted Initial Comments at 6; Pacific Northwest State Agencies Initial Comments at 14; PG&E Initial Comments at 6; Pine Gate Initial Comments at 22; PIOs Initial Comments at 17–18; PJM Initial Comments at 6, 64; SEIA Initial Comments at 7; Southeast PIOs Initial Comments at 44–45; US DOE Initial Comments at 11–12.

[892] Georgia Commission Initial Comments at 4.

[893] APPA Initial Comments at 27–28.

[894] AEE Initial Comments at 10.

[895] Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22–23.

[896] Pine Gate Initial Comments at 22.

[897] DC and MD Offices of People's Counsel Initial Comments at 11–12.

[898] ACEG Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 11.

[899] SEIA Initial Comments at 9–10.

[900] Clean Energy Buyers Initial Comments at 14–15.

[901] Southeast PIOs Reply Comments at 26.

[902] Indicated US Senators and Representatives Initial Comments at 1.

[903] MISO Initial Comments at 34–35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6.

[904] MISO TOs Initial Comments at 18.

[905] OMS Initial Comments at 6.

[906] Exelon Initial Comments at 10–11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7.

[907] Acadia Center and CLF Initial Comments at 9; Clean Energy Buyers Initial Comments at 14–15; ELCON Initial Comments at 12; NESCOE Initial Comments at 27; US DOE Initial Comments at 11–12.

[908] AEE Initial Comments at 10.

[909] Pattern Energy Initial Comments at 24.

[910] Alabama Commission Initial Comments at 7; APPA Initial Comments at 27–28; Dominion Initial Comments at 25; Indicated PJM TOs Initial Comments at 8–9; MISO Initial Comments at 29; NARUC Initial Comments at 8–9; New York TOs Initial Comments at 11–12; NYISO Initial Comments at 8, 20; Pennsylvania Commission Initial Comments at 5–6; PG&E Initial Comments at 7.

[911] NESCOE Initial Comments at 27–28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

planning regions.[912] EEI notes that not all of the factors listed in the NOPR may be relevant for all transmission planning regions during every long-term assessment and explains that private sector, Federal, state, and local public policy goals may diverge or conflict, especially in multi-state regions.[913]

400. ISO–NE requests that the Commission provide transmission providers with flexibility in the consideration of factors for inclusion in each scenario, noting that the factors may vary from study to study depending on the study objectives. Specifically, ISO–NE argues that the Commission should not require that each Long-Term Scenario account for and consistently reflect the first three categories of factors: Federal, state, and local laws and regulations on the future resource mix, decarbonization and electrification, and state-approved integrated resource plans. ISO–NE emphasizes that the Commission should not require local laws to be consistently reflected in and accounted for in Long-Term Scenarios. ISO–NE argues that, in addition to being too prescriptive, such a requirement would introduce unnecessary and substantial administrative burdens and compliance risks with the possibility for inadvertent exclusion of a required law, regulation, or integrated resource plan. Moreover, ISO–NE contends, it would unnecessarily prevent testing of variations with these categories of factors, limiting the usefulness of scenario analysis.[914]

401. Idaho Commission and Idaho Power argue that the NOPR proposal is too prescriptive.[915] PJM advises the Commission not to include too many inflexible details in the implementation of the factors.[916] However, PJM generally supports the NOPR proposal to create seven factors that should guide the development of scenarios with some additions and revisions.[917]

402. NYISO states that the Commission should not prescribe specific categories of factors that transmission providers must use and instead should allow each transmission planning region, in coordination with state entities and stakeholders, to determine to what extent and how the seven categories of factors should be applied.[918] SEIA disagrees, asserting that each proposed category of factors is broad enough to reflect regional differences within the category, but suggests that the Commission provide flexibility on implementation details. SEIA explains that the categories of factors do not set forth specific requirements on how much weight each factor should have in each Long-Term Scenario, what generation mix will result from the mix of factors, or what models to use. SEIA states that the Commission should allow transmission providers to include these implementation details in their manuals.[919]

403. Some commenters express support for some or all of the proposed categories of factors but request that the Commission provide transmission providers with flexibility in how they incorporate the factors into their development of Long-Term Scenarios.[920] For example, TANC requests that the Commission allow transmission planning regions, in consultation with stakeholders, to exclude some of the proposed factors (*i.e.,* regulatory and corporate goals or technology trends) from their development of Long-Term Scenarios.[921] TANC also advocates that the Commission should allow transmission planning regions to determine the manner in which other factors, namely trends, resource requirements, generator interconnection requests, and withdrawals, are incorporated in regional transmission planning studies. Although SPP states that most of the categories of factors are appropriate, it contends that requiring the listed factors to be incorporated, rather than considered, in development of Long-Term Scenarios could overburden the process.[922]

404. NEPOOL states that the categories of factors identified in the NOPR seem generic enough to allow implementation despite regional differences or changes in circumstances over time but contends that the Commission should carefully consider different market structures and potential changes to state policies to ensure that any requirement accommodates regional differences.[923] Pine Gate further requests clarification as to the degree of flexibility that the Commission will grant to transmission providers in how they incorporate each factor into Long-Term Scenarios.[924]

(c) Concerns With the Requirement To Incorporate Categories of Factors

405. Large Public Power argues that the NOPR proposal ignores the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities, as well as Congress' recognition that load-serving entities themselves have a fundamental obligation to build transmission to meet their load.[925] Large Public Power asserts that the NOPR proposal to establish factors that look more broadly than the Commission's core obligations under the FPA threatens to undermine the needs of load-serving entities and their customers.[926] Further, Large Public Power contends that the Commission has no authority to direct the development of transmission facilities.[927] Similarly, some commenters voice concerns with the use of categories of factors to direct transmission investment.[928] Louisiana Commission states that the incorporation of speculative factors would result in a large-scale transmission build-out to accommodate the policy preference of some, at the cost of all.[929]

406. Undersigned States claim that the proposed requirement that each Long-Term Scenario ''incorporate and be consistent'' with certain factors does not address potentially irresolvable conflicts over how certain factors affect the future resource mix and demand.[930] PPL criticizes the NOPR for failing to explain how to translate the proposed factors into usable assumptions that can feed into transmission planning models, leading to increased uncertainty for transmission developers and greater difficultly in financing transmission projects or gaining siting approval.[931]

(d) Alternative Frameworks

407. Other commenters propose alternative frameworks for incorporating factors in the development of Long-Term Scenarios. PPL believes that the Commission's proposed categories of factors are largely overlapping and can

[912] PG&E Initial Comments at 7.

[913] EEI Initial Comments at 12–13.

[914] ISO–NE Initial Comments at 26–27.

[915] Idaho Commission Initial Comments at 3; Idaho Power Initial Comments at 5.

[916] PJM Initial Comments at 67.

[917] *Id.* at 6, 64.

[918] NYISO Initial Comments at 8, 20.

[919] SEIA Reply Comments at 3–4.

[920] Ameren Initial Comments at 9–12; APPA Initial Comments at 27–28; Arizona Commission Initial Comments at 5; Eversource Initial Comments at 16–17; ISO–NE Initial Comments at 26; LADWP Initial Comments at 3; TANC Initial Comments at 9–10.

[921] TANC Initial Comments at 9–10.

[922] SPP Initial Comments at 7–8.

[923] NEPOOL Initial Comments at 7.

[924] Pine Gate Initial Comments at 22–23.

[925] Large Public Power Initial Comments at 19–20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17–18 (quoting 16 U.S.C. 824q(b)(4)), 19–20).

[926] Large Public Power Initial Comments at 20–21.

[927] *Id.* at 11 (citing 16 U.S.C. 824o(i)(2)).

[928] Industrial Customers Initial Comments at 11; Louisiana Commission Initial Comments at 17–19

[929] Louisiana Commission Initial Comments at 17–19.

[930] Undersigned States Initial Comments at 3.

[931] PPL Initial Comments at 8.

be summarized and replaced by a single factor: reasonable expectations regarding the future resource mix and demand.[932] ENGIE suggests that, because the Commission's proposed factors may be too numerous for transmission providers to model, certain factors (*i.e.,* laws, regulations, and announced retirements) should be fixed while others are varied or studied as sensitivities (*i.e.,* costs, demand, and resource development trends).[933] PIOs state that the Commission must set minimum requirements for some factors, asserting that there is broad support for minimum requirements.[934]

408. GridLab contends that the Commission's proposal to require that transmission providers incorporate specific categories of factors in the development of Long-Term Scenarios cannot be enforced and that such broad factors will not change investment outcomes. GridLab states that the proposed list of factors are a helpful minimum standard and recommends that the Commission focus on whether transmission providers have meaningfully incorporated them into Long-Term Regional Transmission Planning.[935] Further, GridLab avers that local laws and regulations and corporate commitments are difficult to incorporate into Long-Term Regional Transmission Planning in a bottom-up, meaningful way.[936] As an alternative, GridLab suggests that transmission providers could use aggregate assumptions and indicative scenario design and allow state and local agencies, as well as other stakeholders, to provide inputs into scenario development, and then evaluate whether the resulting scenarios are consistent with state, local, and corporate commitments.[937]

iii. Commission Determination

409. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate the seven specific categories of factors proposed in the NOPR, as modified in this final order, in the development of Long-Term Scenarios. Specifically, as discussed in more detail below, transmission providers must incorporate in the development of Long-Term Scenarios: (1) Federal, federally-recognized Tribal,[938] state, and local laws and regulations affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[939] We address each of these categories of factors in the Specific Categories of Factors determination section below.

410. We find that existing regional transmission planning requirements fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.[940] Many commenters in this proceeding, even some that may oppose the prescriptiveness of the requirement or otherwise request more flexibility in how transmission providers account for factors affecting Long-Term Transmission Needs,[941] generally agree that the categories of factors outlined in the NOPR account for many of the known determinants of such needs. We find that incorporating the seven categories of factors in the development of Long-Term Scenarios is necessary because these categories of factors are essential to identifying Long-Term Transmission Needs. Further, we find that requiring transmission providers to incorporate the enumerated categories of factors in Long-Term Regional Transmission Planning will help to ensure that transmission providers are accounting for known and identifiable drivers of Long-Term Transmission Needs.

411. We are not persuaded by commenters' arguments that certain of the categories of factors may not be relevant in certain transmission planning regions and therefore that transmission providers should not be required to incorporate those categories of factors in the development of Long-Term Scenarios.[942] We decline to allow transmission providers to exclude some of the proposed categories of factors from being incorporated in the development of Long-Term Scenarios, as certain commenters request, because we conclude that each category of factors includes important determinants of Long-Term Transmission Needs. We are concerned that not requiring incorporation of all of the proposed categories of factors in Long-Term Scenarios would increase the likelihood that transmission providers will continue to underestimate—or omit entirely—certain known determinants of Long-Term Transmission Needs in their regional transmission planning processes.

412. In response to AEE's request, we affirm that the seven categories of factors adopted in this final order are the minimum set of known determinants of Long-Term Transmission Needs that transmission providers must incorporate into the development of their Long-Term Scenarios, and we decline to adopt the NOPR proposal to require transmission providers to demonstrate on compliance that the incorporation of additional categories of factors is consistent with or superior to any final order in this proceeding.[943] Transmission providers may be aware of additional categories of factors beyond those adopted in this final order that drive Long-Term Transmission Needs and, thus, should be incorporated into the development of Long-Term Scenarios. While transmission providers may incorporate additional categories of factors into the development of Long-Term Scenarios, we require in this final order that each Long-Term Scenario remains plausible, as discussed further below.

413. We clarify that incorporating each category of factors into the development of Long-Term Scenarios means more than merely considering each category of factors in the development of Long-Term Scenarios.[944] Incorporating a category of factors in the development of Long-Term Scenarios means that transmission providers must use factors in the category, for each factor individually or collectively, to determine the assumptions that will be used in the development of Long-Term Scenarios. Incorporating a category of factors into the development of Long-Term

[932] *Id.* at 7.

[933] ENGIE Initial Comments at 3.

[934] PIOs Reply Comments at 10.

[935] GridLab Initial Comments at 21–22.

[936] *Id.* at 22.

[937] *Id.*

[938] We emphasize that we are requiring transmission providers to incorporate laws and regulations into Long-Term Scenario development. As noted earlier, while we are providing this opportunity for federally-recognized Tribes to voluntarily participate, we are not imposing any requirements on them to participate.

[939] Modifications to the title of Factor Categories One, Two, Four, and Seven are discussed in the Specific Categories of Factors determination section.

[940] NOPR, 179 FERC ¶ 61,028 at PP 50–51.

[941] *See, e.g.,* EEI Initial Comments at 12–13; PJM Initial Comments at 64–67.

[942] See, *e.g.,* EEI Initial Comments at 12–13; SPP Initial Comments at 7–8.

[943] AEE Initial Comments at 10.

[944] Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22–23.

Scenarios does not require exacting precision; transmission providers may generalize how all of the discrete factors in a category of factors will, in the aggregate, affect the development of Long-Term Scenarios.[945] However, we expect that similar factors (or groups of factors) affecting a single assumption used in the development of Long-Term Scenarios will have an additive effect on that assumption.[946] We also expect that incorporating a category of factors into the development of Long-Term Scenarios will result in scenarios that differ from scenarios lacking that specific category of factors; that is, the incorporation of a category of factors should have a measurable impact on the Long-Term Scenario, compared to that same Long-Term Scenario, all else equal, if it had not incorporated that category of factors.

414. We believe that the best-available data requirement, which we adopt and discuss further below, should mitigate concerns that transmission providers may undermine Long-Term Regional Transmission Planning by not incorporating categories of factors in a meaningful way.[947] The best-available data requirement will ensure that the data inputs that transmission providers use to incorporate categories of factors are timely, developed using best practices, and diverse and expert perspectives. We also clarify that, as a consequence of the requirement that all Long-Term Scenarios must be plausible, as well as the requirement that all Long-Term Scenarios must be diverse, both of which we adopt and discuss below, transmission providers must incorporate the categories of factors in the development of Long-Term Scenarios in a way that results in plausible and diverse Long-Term Scenarios.

415. As to the factors within each category that transmission providers must account for when they incorporate each category of factors in the development of Long-Term Scenarios, we require transmission providers to account for the factors that they have determined are likely to affect Long-Term Transmission Needs. As explained above, these Long-Term Transmission Needs include, but are not limited to, evolving reliability concerns and changes in the resource mix, and changes in demand. For each factor (or group of similar factors) within each category of factors that transmission providers identify, in coordination with stakeholders through an open and transparent process as described below, transmission providers must make a determination as to how that factor (or group of similar factors) is likely to affect Long-Term Transmission Needs. Transmission providers must then account for the factors that they have determined are likely to affect Long-Term Transmission Needs in the development of the Long-Term Scenarios used in Long-Term Regional Transmission Planning. We clarify, however, that transmission providers in a transmission planning region need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs.

416. We also clarify that a category of factors (*e.g.,* Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification) differs from a specific factor (*e.g.,* a specific state law with a decarbonization requirement). We make this distinction because some commenters use only the word ''factors'' when describing the categories of factors proposed in the NOPR.[948]

417. We disagree with commenters that the categories of factors requirements are too prescriptive,[949] and we believe that the framework adopted in this final order requiring transmission providers to incorporate categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility. Transmission providers have discretion to determine whether specific factors must be accounted for within each category (*i.e.,* if the specific factor will likely affect Long-Term Transmission Needs), how to account for specific factors in the development of Long-Term Scenarios (*e.g.,* the method and data used to forecast resource retirements), and how to vary the treatment of each category of factors across Long-Term Scenarios (*e.g.,* assume all forecasted resource retirements materialize in some but not all Long-Term Scenarios), so long as transmission providers assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities identified in the first three categories of factors—that transmission providers have determined are likely to affect Long-Term Transmission Needs—are fully met (as discussed below). We believe that each proposed category of factors is broad enough to allow the transmission providers in each transmission planning region to reflect regional differences within the category, as noted by SEIA and NEPOOL.[950] In response to PG&E's request that we allow flexibility for transmission providers to use Long-Term Scenarios that best reflect the individual policy and planning environments in their specific transmission planning regions, and to Pattern Energy's questions about how categories of factors may be modeled,[951] we clarify that transmission providers have the flexibility to develop different Long-Term Scenarios specific to their transmission planning region and develop using assumptions based on the categories of factors.

418. In response to NESCOE, we decline to give transmission providers the flexibility to choose which of the proposed categories of factors to incorporate into Long-Term Scenarios, which NESCOE states would be consistent with the flexibility that the Commission provided to transmission providers in Order No. 1000, where it did ''not . . . require the identification of any particular transmission need driven by any particular Public Policy Requirements.'' [952] As noted in The Overall Need for Reform section, there are deficiencies in the Commission's existing regional transmission planning requirements, including that they fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs. We are concerned that, if transmission providers have flexibility to choose which of the proposed categories of factors to incorporate into the development of Long-Term Scenarios, they will continue to underestimate—or omit entirely—certain known determinants of Long-Term Transmission Needs in their regional

[945] For example, transmission providers could aggregate the effect of corporate goals by leveraging publicly available surveys of corporations' clean energy and electrification goals and then using those surveys to inform the assumptions used to develop Long-Term Scenarios (*e.g.,* 10% more clean energy resources and 10% higher load growth for a Long-Term Scenario that assumes full achievement of those goals than in a Long-Term Scenario that does not consider such goals).

[946] For example, two independent factors that increase the likelihood of future electric storage resource development (*e.g.,* (1) a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030 and (2) a Federal investment tax credit for the deployment of electric storage resources) would have a combined effect that exceeds the effect of either factor alone.

[947] *E.g.,* ACEG Initial Comments at 28.

[948] *E.g.,* AEE Initial Comments at 9; Evergreen Action Initial Comments at 4.

[949] ISO–NE Initial Comments at 26; NYISO Initial Comments at 8, 20; PJM Initial Comments at 67.

[950] NEPOOL Initial Comments at 7; SEIA Reply Comments at 3–4.

[951] Pattern Energy Initial Comments at 24; PG&E Initial Comments at 7.

[952] NESCOE Initial Comments at 27–28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

transmission planning processes. Additionally, we note that transmission needs are distinct from categories of factors: as explained above, categories of factors, and specific factors therein, form the basis for assumptions that will be used in the development of Long-Term Scenarios that transmission providers will then use to identify Long-Term Transmission Needs.

419. We also disagree with arguments that we are directing the development of specific transmission facilities.[953] As an initial matter, transmission providers retain discretion to determine how specific factors will affect Long-Term Transmission Needs. Moreover, the categories of factors requirements adopted in this final order do not create new transmission needs that did not previously exist, but rather, they improve regional transmission planning processes by requiring transmission providers to identify Long-Term Transmission Needs across a plausible and diverse range of future scenarios and to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. If transmission providers do not account in Long-Term Regional Transmission Planning for known determinants of Long-Term Transmission Needs, then those needs would still exist and would likely be resolved, if at all, in a relatively inefficient or less cost-effective manner (*e.g.,* in a piecemeal fashion through local transmission planning processes and/or generator interconnection processes). We are not requiring that transmission providers select any particular Long-Term Regional Transmission Facility and therefore are not directing the development of any particular transmission facilities. Finally, we clarify that while the requirement for transmission providers to incorporate the seven categories of factors adopted in this final order into the development of Long-Term Scenarios is intended to ensure that Long-Term Regional Transmission Facilities are identified for selection to more efficiently or cost-effectively address Long-Term Transmission Needs, we do not believe that concerns over whether a transmission provider appropriately implemented this requirement represent an appropriate basis on which to challenge the cost allocation for one or more individual Long-Term Regional Transmission Facilities. Rather, whether the allocation of costs is just and reasonable and not unduly discriminatory is governed by the requirement that costs be roughly commensurate with benefits, as discussed in the Regional Transmission Cost Allocation section below.

420. We disagree with Large Public Power's argument that we are ignoring the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities.[954] As described below, we are requiring all Long-Term Scenarios to be consistent with and fully account for factors in Factor Category Three, which includes state-approved integrated resource plans and the expected supply obligations of load-serving entities. Therefore, transmission providers are required to plan to meet the needs of load-serving entities.

421. We decline to adopt more specific minimum requirements than those described herein for incorporating categories of factors in the development of Long-Term Scenarios, as requested by some commenters.[955] We believe that the requirements adopted herein, coupled with the other Long-Term Scenarios requirements, including the plausible and diverse and best available data requirements, are sufficiently detailed to address the need for reform without limiting regional flexibility.

b. Specific Categories of Factors

i. NOPR Proposal

422. In the NOPR, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) Federal, state, and local laws and regulations that affect the future resource mix and demand;[956] (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.[957]

(a) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations That Affect the Future Resource Mix and Demand (Factor Category One)

(1) Comments

423. Many commenters support the proposed requirement that each Long-Term Scenario incorporate and be consistent with the Federal, state, and local laws and regulations that affect the future resource mix and demand.[958] AEE, Clean Energy States, and Acadia Center and CLF argue that laws and regulations implementing clean energy and decarbonization policies will be key drivers in changes to the resource mix and demand.[959] Moreover, AEE notes, 38 states and the District of Columbia have adopted renewable portfolio standards, many of which have been enacted in statute and constitute binding commitments on utilities and retail energy providers.[960] Clean Energy States similarly assert that the 21 states (plus the District of Columbia and Puerto Rico) with 100% clean energy policies account for 42.3% of United States power sales as of 2020, 49.4% of United States customer accounts, and 51% of United States population.[961] Clean Energy States argue that altogether, these states could see an aggregated demand for 800 TWh of new energy generation to meet their targets.

424. AEE, DC and MD Offices of People's Counsel, and SEIA agree that transmission providers should incorporate the effects of Federal, state, and local laws and regulations on

[953] *E.g.,* Large Public Power Initial Comments at 20–21; *see also* Alabama Commission Initial Comments at 4; Industrial Customers Initial Comments at 10; Louisiana Commission Initial Comments at 17–19; Pennsylvania Commission Initial Comments at 6.

[954] Large Public Power Initial Comments at 19–20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17–18 (quoting 16 U.S.C. 824q(b)(4)), 19–20.

[955] *E.g.,* PIOs Reply Comments at 10.

[956] NOPR, 179 FERC ¶ 61,028 at P 104 n.189. The Commission explained that ''state or federal laws or regulations'' meant ''enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or municipality, or at the federal level.''

[957] *Id.* P 104.

[958] Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 9–10; Breakthrough Energy Initial Comments at 14; California Commission Initial Comments at 17; Clean Energy Associations Initial Comments at 10–11; Clean Energy States Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Exelon Initial Comments at 10–11; New England for Offshore Wind Initial Comments at 2; OMS Initial Comments at 6; Pacific Northwest State Agencies at Initial Comments at 14; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; WE ACT Initial Comments at 4–5.

[959] Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 10; Clean Energy States Initial Comments at 3.

[960] AEE Initial Comments at 10 (citing Energy Info. Admin., *Renewable Energy Explained, Portfolio Standards* (June 29, 2021), *https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php*).

[961] Clean Energy States Initial Comments at 3 (citing Clean Energy States Alliance, *100% Energy Collaborative, https://www.cesa.org/projects/100-clean-energy-collaborative/*).

renewable energy development into development of Long-Term Scenarios.[962] City of New York states that government action that bears the force of law should be reflected in baseline transmission planning studies and not considered as merely one of multiple factors used to develop Long-Term Scenarios.[963]

425. Southeast PIOs argue that concerns that requiring the incorporation of local laws and regulations in the development of Long-Term Scenarios is unduly burdensome are misplaced at this stage because the details of how it will be done will be established during compliance proceedings.[964]

426. PIOs argue that the Commission should require the same level of engagement with Tribal governments as it does with states and that the Commission should clarify that Long-Term Scenarios must incorporate relevant aspects of Tribal policies.[965]

427. Acadia Center and CLF claim that the Commission should clarify that state laws and regulations that affect the future resource mix and demand include state laws and regulations that affect demand management, such as energy efficiency, distributed generation, flexible load, and demand response because laws and initiatives in this area will also affect transmission needs while providing grid solutions.[966]

428. Center for Biological Diversity states that the Commission must include all Executive Actions, not just laws and regulations, as factors in Long-Term Regional Transmission Planning. Center for Biological Diversity states that allowing transmission providers to decide whether to consider Executive Orders fails to provide stakeholders with the type of clarity that is a goal of the NOPR.[967]

429. As noted above, some commenters oppose the overall categories of factors requirement in this final order and argue that requiring transmission providers to incorporate certain factors, such as laws and regulations that affect the resource mix, will force transmission providers to settle irresolvable conflicts among state policies and conduct transmission planning that accommodates the policy preferences of some, at the cost of all.[968]

430. Some commenters acknowledge that state laws and regulations may affect the future resource mix and demand but argue against mandatory inclusion such that they cannot discount certain Federal, state, and local laws and regulations.[969] Idaho Power states that the NOPR proposal does not provide transmission providers with the flexibility necessary to create transmission planning regions that span multiple states and could cause non-jurisdictional entities to opt out of regional transmission planning.[970] NYISO states that the final order should not require transmission providers to assume across all scenarios the full achievement of all Federal, state, and local laws and regulations that could drive the need for transmission. NYISO also does not think that the final order should require the identification of all Federal, state, and local laws and regulations that may drive the need for transmission over the 20-year transmission planning horizon, but instead should provide each transmission planning region with flexibility.[971]

431. Although Duke agrees that many of the categories of factors identified in the NOPR capture a minimum list of factors that are expected to drive changes in the resource mix and demand, it does not support the inclusion of local laws and regulations.[972]

(2) Commission Determination

432. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, in the development of Long-Term Scenarios. We find that the factors in this category have been, and will continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. Accordingly, we find that failing to account for factors in Factor Category One would hamper the identification, evaluation, and selection of Long-Term Regional Transmission Facilities that are potentially more efficient or cost-effective solutions to Long-Term Transmission Needs.

433. We clarify that factors in Factor Category One include, among other things, legally binding obligations, incentives (*e.g.,* tax credits), and/or restrictions promulgated by policymakers that will affect new or existing generators, or demand. Further, as discussed in the Additional Categories of Factors section below, we recognize that energy equity and justice laws and regulations are also potential factors within Factor Category One to the extent that they are likely to affect Long-Term Transmission Needs.

434. As discussed in further detail below in the Additional Categories of Factors section, we modify the NOPR proposal for Factor Category One to include federally-recognized Tribal laws and regulations affecting the resource mix and demand because we are persuaded by commenters that contend that such factors have a similar potential to affect Long-Term Transmission Needs as Federal, state, and local laws and regulations. Federally-recognized Tribal laws and regulations mean the legally binding obligations, incentives, and/or restrictions promulgated by federally-recognized Tribes that will affect new or existing generators, or demand. We make similar modifications to Factor Category Two and Factor Category Seven, as discussed in the Factor Category Two and Factor Category Seven sections below.

435. We are not persuaded by Louisiana Commission's argument that requiring transmission providers to incorporate certain factors, such as Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, would result in a transmission buildout that only accommodates the policy preferences of some stakeholders, at the cost of all transmission customers.[973] Similarly, we are not persuaded by Undersigned States' contention that policy differences among states may be irresolvable, and therefore the Commission should not require transmission providers to account for laws and regulations in their Long-Term Scenarios.[974] First, every policy choice—from Federal tax incentives and state regulation of generation, down to local economic development policies—that changes the quantity and location of generation and load contributes to changes in transmission needs. Accordingly, all transmission buildout—whether it occurs through a

[962] AEE Initial Comments at 17–18, 22; DC and MD Offices of People's Counsel Reply Comments at 5–6; SEIA Initial Comments at 7–8.

[963] City of New York Initial Comments at 7.

[964] Southeast PIOs Reply Comments at 26.

[965] PIOs Reply Comments at 15.

[966] Acadia Center and CLF Initial Comments at 9.

[967] Center for Biological Diversity Initial Comments at 3, 9–12.

[968] Louisiana Commission Initial Comments at 17–18; Undersigned States Initial Comments at 3.

[969] Ameren Initial Comments at 9–10; NESCOE Initial Comments at 27–28; NYISO Initial Comments at 8, 20.

[970] Idaho Power Initial Comments at 7.

[971] NYISO Initial Comments at 8.

[972] Duke Initial Comments at 13–14.

[973] Louisiana Commission Initial Comments at 17.

[974] Undersigned States Initial Comments at 3.

local or regional transmission plan, or through a near-term transmission planning process or a more forward-looking one—is a reflection, at least in part, of Federal, federally-recognized Tribal, state, and local laws and regulations that drive transmission needs. Rather than a unique feature of Long-Term Regional Transmission Planning, transmission planning of any kind will inherently reflect the policy choices of multiple decisionmakers, because the quantity and location of generation and load are shaped by multiple decisionmakers.

436. Second, we find that requiring transmission providers to properly account for known determinants of Long-Term Transmission Needs is necessary to ensure just and reasonable rates. Specifically, because, as described above, Long-Term Transmission Needs driven by disparate policy decisions would continue to exist, regardless of whether they were identified in Long-Term Regional Transmission Planning, failing to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs will result in unjust and unreasonable rates. We note that some policy decisions are reflected in laws and regulations, which can affect load-serving entities' supply obligations, and in transmission planning regions with vertically integrated utilities, some policy decisions are reflected in the integrated resource plans approved by retail regulators.

437. We are not endorsing the merits of any specific Federal, federally-recognized Tribal, state, or local laws and regulations or of any specific state-approved integrated resource plans. We emphasize that the Commission's policies are technology neutral, and we are not establishing a preference for certain types of generation or energy end uses. We acknowledge that, in some instances, a policy choice in one jurisdiction may reduce or negate the effect of a policy choice in another jurisdiction. However, the fact that certain factors may have conflicting effects on Long-Term Transmission Needs is not a basis to conclude that the effects of laws and regulations or state-approved integrated resource plans should be ignored or discounted.

(b) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations on Decarbonization and Electrification (Factor Category Two)

(1) Comments

438. Several commenters support the proposed requirement that Long-Term Scenarios incorporate Federal, state, and local laws and regulations on decarbonization and electrification.[975] Illinois Commission notes that, in Illinois, the Climate and Equitable Jobs Act of 2021 will affect future demand and the supply mix and that Long-Term Regional Transmission Planning will be critical to meeting Illinois' policy goals.[976] New England for Offshore Wind states that electrification to meet New England states' greenhouse gas emissions mandates will dramatically increase electricity load and require massive amounts of clean energy.[977] Pattern Energy states that Federal and state legislative efforts to promote decarbonization should be the basis of scenario modeling for generation and demand.[978] Center for Biological Diversity states that the Commission should identify decarbonization as an objective in Long-Term Regional Transmission Planning because it has the authority and responsibility to prioritize decarbonization in the transmission planning process since these policies bear directly on the provision of transmission service.[979]

439. Nevada Commission acknowledges that other state policies and its own integrated resource planning process should be considered in Long-Term Regional Transmission Planning even though it does not support other state policies affecting Nevada ratepayers.[980] Utah Division of Public Utilities states that the impact of state policies should be part of the Long-Term Regional Transmission Planning scenario analysis.[981] Cypress Creek asserts that the Commission should include state policy requirements in a uniform set of assumptions that are applicable across all Long-Term Scenarios.[982]

(2) Commission Determination

440. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification, in the development of Long-Term Scenarios. Similar to Factor Category One, we find that the factors in this category have been, and will continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. We clarify that this category of factors includes legally binding obligations, incentives, and/or restrictions that affect Long-Term Transmission Needs in different ways than Factor Category One, for example, by limiting the carbon intensity of electricity generation or electrifying energy end uses and thereby significantly increasing electricity use in certain sectors of the economy, such as transportation and building heating and cooling. We acknowledge that there could be overlap between Factor Categories One and Two because a certain law or regulation could reasonably be considered to fit into both categories. In such a circumstance, transmission providers must account for the law or regulation in one of the two categories, not both, to avoid double-counting of that factor's anticipated effect on Long-Term Transmission Needs. Since transmission providers must account for and be consistent with, and not discount, factors in the first three categories of factors equally once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs, we do not believe it is necessary to ensure that a certain factor is considered as part of Factor Category One instead of Factor Category Two (or vice versa), but rather it is only necessary to ensure that these factors are accounted for in the development of Long-Term Scenarios.

441. In addition, based on the record before us, we modify the NOPR proposal for Factor Category Two to include federally-recognized Tribal laws and regulations on decarbonization and electrification because we are persuaded by commenters that argue that such factors have the same potential to affect Long-Term Transmission Needs as Federal, state, and local laws and regulations on decarbonization and electrification.

442. Similar to our response in the Factor Category One section to commenters arguing that categories of factors involving Federal, federally-recognized Tribal, state, and local laws and regulations would provide

[975] Acadia and CLF Initial Comments at 9; Center for Biological Diversity Initial Comments at 7–9; Clean Energy Associations Initial Comments at 10–11; DC and MD Offices of People's Counsel Reply Comments at 6; Illinois Commission Initial Comments at 4–5; New England for Offshore Wind Initial Comments at 2–3; Pacific Northwest State Agencies at Initial Comments at 14; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; Renewable Northwest Initial Comments at 19–22.

[976] Illinois Commission Initial Comments at 4–5.

[977] New England for Offshore Wind Initial Comments at 2–3.

[978] Pattern Energy Initial Comments at 26.

[979] Center for Biological Diversity Initial Comments at 7–9 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 89–93).

[980] Nevada Commission Initial Comments at 8.

[981] Utah Division of Public Utilities Reply Comments at 4.

[982] Cypress Creek Reply Comments at 5–6.

preference to some at the cost of all or result in irresolvable conflict,[983] we find that differences in if and how government entities promulgate laws and regulations concerning decarbonization and electrification (*i.e.,* factors in Factor Category Two) do not diminish the effect of such laws and regulations. As such, Long-Term Scenarios must account for these key drivers of Long-Term Transmission Needs so that transmission providers can identify such needs through Long-Term Regional Transmission Planning and can identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs.

(c) State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three)

(1) Comments

443. Several commenters support the proposed requirement that each Long-Term Scenario incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities.[984] NRECA and TAPS state that using Long-Term Scenarios that satisfy expected load-serving entity supply obligations is consistent with FPA section 217(b)(4)'s directive to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.[985] NRECA asserts that this category should be moved to the top of the list of categories of factors because state-approved integrated resource plans and load-serving entity supply obligations will incorporate state laws and regulations affecting resource mix, demand, decarbonization, and electrification. Additionally, NRECA contends that the changing characteristics of the distribution grid, such as distributed energy resources, storage, demand response, energy efficiency, and electrification of demand, will affect load-serving entity needs and should be incorporated in this category of factors.[986] Clean Energy Associations and ACEG agree.[987]

444. APPA and ACEG argue that the final order should focus on the resource plans of load-serving entities and include a requirement for transmission providers to include in their Long-Term Regional Transmission Planning process a requirement to coordinate with load-serving entities.[988] ACEG argues that such a requirement is necessary because not all load-serving entities either own generation or are overseen by a state regulator, meaning that they must rely on the Commission to ensure that transmission planning meets their needs.[989]

445. Several commenters clarify that they support the inclusion of load-serving entity demand as a factor in Long-Term Scenarios.[990] In addition, some commenters support the inclusion of load-serving entity generation resource planning as a factor in Long-Term Scenarios.[991] PIOs argue that the Commission should require load-serving entities to provide their generation and demand forecasts to transmission planning entities.[992] ACEG agrees and argues that PIOs' recommendation will decrease the burden on transmission planning entities and provide them with the information they need to determine the future resource mix.[993]

446. Entergy asserts that the Commission has identified the appropriate factors but explains that not all states conduct commission proceedings related to integrated resource plans and, for those states that do, the timelines are not necessarily the same. Thus, Entergy requests that the Commission clarify that the term ''state-approved utility integrated resource plans'' will be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning. Entergy asserts that such clarification would result in a range of benefits such as consistency of data with current local, state, and Federal laws and expected retirements, additions, and corporate goals.[994]

(2) Commission Determination

447. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Three: state-approved integrated resource plans and expected supply obligations for load-serving entities, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Three because it reflects the outcomes of retail-level regulatory proceedings that will affect Long-Term Transmission Needs. Further, incorporation of Factor Category Three into Long-Term Scenarios will ensure that transmission providers properly account for resource planning and anticipated changes to demand, including increased integration of distributed energy resources. We note that the Commission shares concurrent jurisdiction over the bulk power system with retail regulators,[995] and we agree with commenters that note that FPA section 217(b)(4) directs the Commission to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.[996]

448. In response to commenters that note some retail regulators may review but not formally approve integrated resource plans, we clarify that, for this category of factors, state-approved integrated resource plans includes resource plans that are developed and reviewed through a retail proceeding in jurisdictions where the retail regulator does not formally approve such plans.[997] We grant Entergy's clarification request that the term ''state-approved utility integrated resource plans'' be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning because it would enable a more complete consideration of state-approved integrated resource plans and

[983] Louisiana Commission Initial Comments at 17–19; Undersigned States Initial Comments at 3. Comments originally summarized in PP 404–405.

[984] California Commission Initial Comments at 17; NRECA Initial Comments at 30; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; US Chamber of Commerce Initial Comments at 6–7.

[985] NRECA Initial Comments at 30–31; TAPS Initial Comments at 2, 7–8 (citing NOPR, 179 FERC ¶ 61,028 at P 106); *see also* APPA Initial Comments at 28.

[986] NRECA Initial Comments at 30–31 n.85.

[987] ACEG Reply Comments at 22; Clean Energy Associations Reply Comments at 6–7.

[988] ACEG Reply Comments at 22; APPA Initial Comments at 27–28.

[989] ACEG Reply Comments at 22–23.

[990] ACEG Reply Comments at 22–23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4; PIOs Initial Comments at 18; PIOs Reply Comments at 10.

[991] ACEG Reply Comments at 22–23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4.

[992] PIOs Initial Comments at 19.

[993] ACEG Reply Comments at 23.

[994] Entergy Initial Comments at 15–16.

[995] *Compare* 16 U.S.C. 824d(a) (providing the Commission authority to regulate the rates charged by public utilities in connection with the transmission or wholesale sale of electric energy), *with id.* 824(a) (reserving certain state authorities).

[996] 16 U.S.C. 824q(b)(4) (''The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'').

[997] Entergy Initial Comments at 15–16.

expected supply obligations for load-serving entities.

449. In response to APPA and ACEG's request for the Commission to require transmission providers to coordinate with load-serving entities,[998] we note that we require transmission providers, as described in further detail below, to provide an open and transparent process in their OATT that provides stakeholders, including load-serving entities, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.[999] However, in response to PIOs' request that the Commission require load-serving entities to provide their generation and demand forecast to transmission providers, we agree that such information will assist transmission providers in developing Long-Term Scenarios. Therefore, consistent with the information exchange transmission planning principle established in Order No. 890,[1000] we require load-serving entities that are taking transmission service pursuant to an OATT to provide transmission providers with information on the load-serving entities' projected loads and resources over the planning horizon.

(d) Trends in Technology and Fuel Costs Within and Outside of the Electricity Supply Industry, Including Shifts Toward Electrification of Buildings and Transportation (Factor Category Four)

(1) Comments

450. Several commenters emphasize the importance of incorporating assumptions regarding shifts towards electrification in Long-Term Scenarios.[1001] Clean Energy Buyers assert that regional flexibility should not be used to diminish the representation in Long-Term Scenarios of significant load growth from the commercial and industrial sectors and electrification of transportation.[1002] Likewise, DC and MD Offices of People's Counsel assert that regional flexibility should be reflected in the actual inputs for these factors, rather than their inclusion in or exclusion from Long-Term Scenarios, noting, for example, that electrification forecasts in some areas are increasing load growth estimates by 30%.[1003] Clean Energy Associations argue that, to keep pace with changes in supply and demand, Long-Term Scenarios should incorporate aging infrastructure and planned replacements, along with load and generation trends informed by both historical data and applicable policy drivers.[1004]

451. Other commenters emphasize the trends in specific technology costs, such as long-duration storage. ENGIE states that advances in longer-duration storage and advancing photovoltaic technologies may affect the ability to develop resources in areas previously considered to be uneconomic, which could affect the resource and demand mix.[1005] Form Energy argues that the inclusion of diverse, long-duration electric storage technologies would require significantly fewer new transmission needs.[1006]

452. Pine Gate supports the inclusion of trends in technology and fuel costs in Long-Term Scenarios; however, Pine Gate requests that the Commission clarify what type of data would constitute a ''trend'' and how it expects transmission providers to assure that trend-related input is objective and representative of the ''best available data.'' [1007] Similarly, US DOE recommends that the Commission clarify whether the term ''trends in technology and fuel costs'' refers to trends in fuel cost and trends in technology, or rather trends in the cost of fuel and trends in the cost of technology. If the Commission is referring to the former, US DOE recommends that the Commission consider the phrase ''trends in fuel costs and in the cost, performance, and availability of generation, storage, and transmission technologies.'' US DOE further recommends that the Commission provide a non-exhaustive list of examples of cost and technology trends that transmission planners could consider.[1008]

453. SEIA recommends that the Commission direct transmission providers to use the data and models used in NREL's Electrification Futures Study, Solar Futures Study, Storage Futures Study, and Transportation Futures Study.[1009] PIOs disagree with granting discretion to transmission providers to define trends in technology and fuel costs because PIOs state that it could empower them to distort the modeling process and create Long-Term Scenarios that are meaningless.[1010]

454. PIOs argue that the Commission should require transmission providers to use certain values for trends in technology and fuel costs within and outside of the electricity supply industry.[1011]

455. New York TOs argue that trends in technology costs are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider.[1012] Similarly, PPL criticizes the Commission's proposed requirement that transmission providers forecast trends in technology without providing concrete assumptions to use, or without a guarantee for cost recovery for investments that are based on those uncertain forecasts.[1013]

(2) Commission Determination

456. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Four: trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Four into the development of Long-Term Scenarios because the relative cost of constructing and operating different types of generation or storage resources and the relative cost of electrifying certain energy end uses will affect Long-Term Transmission Needs. We further find that this requirement is necessary to ensure that transmission providers

[998] ACEG Reply Comments at 22; APPA Initial Comments at 27–28.

[999] *See infra* Stakeholder Process and Transparency section.

[1000] The information exchange transmission planning principle requires network transmission customers to submit information on their projected loads and resources on a comparable basis (*e.g.,* planning horizon and format) as used by transmission providers in planning for their native load. Point-to-point transmission customers are required to submit their projections for need of service over the planning horizon and at what receipt and delivery points. To the extent applicable, transmission customers should also provide information on existing and planned demand resources and their impact on demand and peak demand. Transmission providers, in consultation with their customers and other stakeholders, must develop guidelines and a schedule for the submittal of such customer information. Order No. 890, 118 FERC ¶ 61,119 at PP 486–487.

[1001] Clean Energy Associations Initial Comments at 11; Clean Energy Buyers Initial Comments at 15–16; DC and MD Offices of People's Counsel Initial Comments at 11–12; ENGIE Initial Comments at 3; PJM Market Monitor Initial Comments at 3.

[1002] Clean Energy Buyers Initial Comments at 15–16.

[1003] DC and MD Offices of People's Counsel Initial Comments at 11–12.

[1004] Clean Energy Associations Initial Comments at 12.

[1005] ENGIE Initial Comments at 3.

[1006] Form Energy Initial Comments at 2–3.

[1007] Pine Gate Initial Comments at 24.

[1008] US DOE Initial Comments at 12–13.

[1009] SEIA Initial Comments at 10.

[1010] PIOs Initial Comments at 19.

[1011] *Id.* at 17–19.

[1012] New York TOs Initial Comments at 11–12.

[1013] PPL Initial Comments at 8.

develop plausible Long-Term Scenarios that account for technological changes expected over the transmission planning horizon, facilitating transmission providers' identification of Long-Term Transmission Needs.

457. As requested by commenters, including US DOE, we modify this category of factors in the final order to clarify that this category of factors is meant to capture changes in the cost, as well as the performance and availability, of certain technologies relevant to the electric industry.[1014] In response to commenters arguing that trends in technology costs are amorphous and should not be included in the final order as a required category of factors, we disagree. However, as discussed above, we grant transmission providers discretion to determine whether specific trends identified in Factor Category Four are likely to affect Long-Term Transmission Needs and how to account for those specific trends in Long-Term Scenarios.[1015] As discussed in further detail below, transmission providers also have some discretion to discount or place more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category.

458. In response to comments from US DOE,[1016] we clarify that trends in fuel costs and in the cost, performance, and availability of generation, storage, and building and transportation electrification technologies may include, but are not limited to, cost and technology trends for: utility-scale generation construction costs for different generating technologies; distributed energy resources; storage technologies with differing duration limitations; carbon capture and sequestration; small modular nuclear; light-, medium-, and heavy-duty electric vehicles and electric vehicle supply equipment; and ground- and air-source heat pumps. While we agree with US DOE that transmission providers should consider trends in the cost, performance, and availability of transmission technologies as part of their evaluation of potential solutions to Long-Term Transmission Needs, we do not believe that these trends should be included as factors in this category because trends in the cost, performance, and availability of transmission technologies do not drive Long-Term Transmission Needs. We also agree with commenters that note that the effects of the factors in this category may vary significantly, such as shifts towards electrification leading to significant load growth, or cost reductions for emerging technologies, like long-duration electric storage resources, mitigating some new transmission needs.

(e) Resource Retirements (Factor Category Five)

(1) Comments

459. Several commenters support the proposed requirement that each Long-Term Scenario incorporate resource retirements as a category of factors.[1017] PJM Market Monitor states that PJM faces the potential for the retirement of large coal resources and that the PJM capacity market design and the transmission planning process need to identify these specific resources well in advance and ensure an efficient response to obviate the need for nonmarket cost-of-service contracts to retain generation while transmission is constructed.[1018]

460. PIOs and NYISO both argue that the Commission should further specify that transmission providers must incorporate expected trends in resource retirements rather than just announced retirements into Long-Term Scenarios.[1019] PIOs state the Commission should require transmission providers to (1) specify how they will use generator age and condition data to predict retirements, (2) include announced retirements, and (3) specify how they will reflect trends and incentives for distributed energy resources, as well as how they will quantify these trends.[1020]

461. NYISO states that the final order should confirm that each transmission planning region has the authority and flexibility to account for likely resource retirements that have not been announced by the resource based on factors that include the facility's age, its emission profile, applicable laws and regulations, and other factors.[1021] Similarly, Pine Gate asserts that resource retirements should be included at the earliest opportunity as there is often a significant gap of time between when a public announcement is made and when the official notice of deactivation is communicated to the transmission provider.[1022]

462. SEIA states that transmission providers should only be required to include the retirement of resources that have provided notice of pending retirement pursuant to the applicable tariff provisions.[1023] PJM supports engaging in transparent economic impact analyses of generation resource retirements but asserts that such analyses might disclose confidential information about specific generators. Therefore, PJM contends that the Commission will need to provide clear direction on how it wishes to address these issues, especially since masking of data is not a practical solution once the transmission case is released.[1024]

(2) Commission Determination

463. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Five: resource retirements, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Five because resource retirements expected over the transmission planning horizon will affect Long-Term Transmission Needs. Commenters generally support requiring this category of factors, but commenters disagree as to how transmission providers should account for projected resource retirements that have not been publicly announced.[1025]

464. In response to those commenters, we clarify that, to develop plausible Long-Term Scenarios, transmission providers must, in incorporating Factor Category Five into the development of Long-Term Scenarios, account for likely resource retirements beyond those that have been publicly announced. The record indicates that resource retirements have significantly influenced the supply of electricity in the past and are expected to do so in the coming decades.[1026] The North

[1014] Pine Gate Initial Comments at 24; US DOE Initial Comments at 12.

[1015] *See* New York TOs Initial Comments at 11–12; PPL Initial Comments at 8.

[1016] US DOE Initial Comments at 12–13.

[1017] Breakthrough Energy Initial Comments at 14; NRECA Initial Comments at 31; NYISO Initial Comments at 24; PIOs Initial Comments at 21; SPP Market Monitor Initial Comments at 9; *see also* PJM Market Monitor at 3 ("PJM faces the potential retirement . . . of a significant amount of coal resources in the next five years. Both the PJM capacity market and design and the transmission planning process need to identify these specific resources well in advance and plan for their retirement in order to ensure an efficient response and to obviate the need for nonmarket cost of service contracts to retain the generation while transmission is constructed.").

[1018] PJM Market Monitor Initial Comments at 3.

[1019] NYISO Initial Comments at 24; PIOs Initial Comments at 21.

[1020] PIOs Initial Comments at 21.

[1021] NYISO Initial Comments at 24.

[1022] Pine Gate Initial Comments at 24.

[1023] SEIA Initial Comments at 10.

[1024] PJM Initial Comments at 6, 69.

[1025] NYISO Initial Comments at 24; Pine Gate Initial Comments at 24; PIOs Initial Comments at 21.

[1026] *See supra* note 241; Colorado Consumer Advocate Initial Comments, attach. 7 (US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (Aug. 2017)) at 13–14 (stating that 132 GW of generation capacity retired between 2002 and 2016—approximately 15% of the installed capacity in 2002—due to the advantaged economics

American Electric Reliability Corporation's 2021 Long-Term Reliability Assessment reports nearly 50 GW of confirmed thermal generation resource retirements by 2026 and acknowledges that many more are yet to be announced.[1027] In addition, the record reflects that publicly announced resource retirements are only a fraction of the resource retirements expected over the required 20-year transmission planning horizon.[1028] Given the significance of resource retirements, and the limited scope of publicly announced resource retirements, we find that transmission providers must account for expected retirements that have not been publicly announced to meet this final order's requirement that transmission providers develop a plausible set of Long-Term Scenarios.[1029]

465. We provide flexibility to transmission providers to propose on compliance with this final order how to account for resource retirements that might take place over the transmission planning horizon, in addition to those that have been publicly announced. We note, for example, that transmission providers could propose to account for expected retirements by considering factors such as a generating facility's age, its emissions profile, its projected costs and revenues, and any applicable laws and regulations that may affect a generating facility's continued operation over the transmission planning horizon.[1030] To the extent that certain laws and regulations identified by stakeholders in Factor Categories One and Two will necessitate the retirement of certain resources, we reiterate that transmission providers must develop Long-Term Scenarios that are consistent with such laws and regulations.

466. In response to PJM's concerns that conducting transparent economic impact analyses of generation resource retirements could lead to the disclosure of confidential information about specific generators, we note that the Commission has previously acknowledged that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.[1031] We note that we are not specifying how transmission providers must estimate resource retirements, and we clarify that transmission providers may include what they believe to be appropriate confidentiality protections in their proposals to account for resource retirements that might take place over the transmission planning horizon. The Commission will evaluate those proposals by using the established principles in Order No. 890,[1032] as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

(f) Generator Interconnection Requests and Withdrawals (Factor Category Six)

(1) Comments

467. Several commenters support the proposed requirement that each Long-Term Scenario incorporate generator interconnection requests and withdrawals.[1033] Pattern Energy argues that generation interconnection queues are indicative of the market for generation capacity additions and should also be a major source for generation assumptions in both near-term and long-term scenario planning.[1034] SEIA supports the proposed requirement with the caveat that transmission providers should only include interconnection customers that have signed a facilities study agreement, or other applicable study agreement.[1035] Cypress Creek asserts that the Commission should require transmission providers to include the proposed generator interconnection requests in the queue that have completed a system impact study as part of a uniform set of assumptions applicable across all scenarios.[1036]

468. CAISO and MISO state that their regional transmission planning processes already include projects in the generator interconnection queue.[1037] MISO further explains that it considers the generator interconnection queue when determining the location where future generation will interconnect, but MISO also states that transmission providers and their stakeholders need to have flexibility, including how to consider trends in interconnection queue requests.[1038] Further, MISO argues that ''generation interconnection requests and withdrawals'' as stated in the NOPR is unclear regarding how the transmission provider must weigh withdrawals differently than requests. Therefore, MISO requests that the Commission revise the NOPR proposal to require transmission providers to ''consider activity in the generation interconnection queue.'' [1039]

469. Nebraska Commission asserts that the Commission should not include interconnection request withdrawals as a factor because it does not follow the Commission's cost causation principles and would incentivize additional interconnection requests. For example, Nebraska Commission states, most interconnection requests in SPP are duplicative, and entities compare costs among their requests once they are analyzed. Nebraska Commission asserts that such requests could be used to game the transmission planning process, create additional backlogs in the interconnection queue, and shift costs from interconnection customers to transmission customers.[1040]

470. Likewise, Omaha Public Power claims that, until generator interconnection reform is enacted, the use of interconnection queues and withdrawals as factors will lead to

of natural gas-fired generation, low electricity demand growth, the deployment of variable energy resources, and regulatory requirements); *see also, e.g.,* AEP Initial Comments at 4 n.12.

[1027] SEIA Initial Comments at 9 (citing North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment,* at 30, 35 (Dec. 2021)). The North American Electric Reliability Corporation states that long-range retirement projects based on confirmed retirements could be ''significantly understated'' because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas. The North American Electric Reliability Corporation 's 2021 reported retirements through 2026 increased 126% compared to the North American Electric Reliability Corporation's 2020 estimates; and the North American Electric Reliability Corporation's 2022 reported retirements through 2026 increased compared to the North American Electric Reliability Corporation 's 2021 retirements. *See* North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment,* at 35 (Dec. 2021); NERC, *2022 Long-Term Reliability Assessment,* at 17 (Dec. 2022).

[1028] For example, announced retirements account for less than half of MISO's projected retirements over a 20-year transmission planning horizon. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report,* at 14–19, (Dec. 2021), *https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf*).

[1029] *See infra* Types of Long-Term Scenarios section.

[1030] For example, MISO assumes age-based resource retirements which vary by resource type and scenario, over a 20-year transmission planning horizon. In a 2021 study, MISO assumes coal-fired resources will retire at age 46 in one scenario, and age 36 in another. MISO assumes utility-scale solar resources will retire at age 25 in every scenario. MISO also incorporates resource retirements announced by the resource owner, stated in an integrated resource plan, or filed in MISO's Attachment Y. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report,* at 14–19, (Dec. 2021), *https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf*).

[1031] *Sw. Power Pool, Inc.,* 137 FERC ¶ 61,227, at P 20 (2011).

[1032] Order No. 890, 118 FERC ¶ 61,119 at PP 471–476.

[1033] Breakthrough Energy Initial Comments at 14; Cypress Creek Reply Comments at 5–7.

[1034] Pattern Energy Initial Comments at 26.

[1035] SEIA Initial Comments at 10.

[1036] Cypress Creek Reply Comments at 5–7.

[1037] CAISO Initial Comments at 34; MISO Initial Comments at 35.

[1038] MISO Initial Comments at 35–36.

[1039] *Id.* at 36.

[1040] Nebraska Commission Initial Comments at 4–5.

scenario inaccuracy due to the size of interconnection backlogs and speculative nature of many queued projects.[1041] Dominion also opposes using the number and size of interconnection requests as a basis for transmission planning because speculative interconnection requests could stimulate transmission development in areas slated for development by private interests.[1042]

471. PJM Market Monitor states that, while there are many comments on the significant renewable resources PJM will connect to its grid, based on historic completion rates and effective load carry capability derate factors, only 5.6% of renewable resources are expected to go into service.[1043]

(2) Commission Determination

472. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Six: generator interconnection requests and withdrawals, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Six because generation interconnection queues provide important information about future generation development over the transmission planning horizon and therefore affect Long-Term Transmission Needs. Multiple RTOs/ISOs explain that their regional transmission planning processes already account for generation projects in the interconnection queue, but MISO notes that transmission providers need flexibility in how to incorporate that data into the development of Long-Term Scenarios.[1044] In response to MISO's concerns, we reiterate that transmission providers have discretion to determine how to account for all factors, including interconnection requests and withdrawals, in Long-Term Scenarios.

473. We disagree with commenters that argue that, because many interconnection requests are speculative and/or duplicative, requiring transmission providers to incorporate Factor Category Six into the development of Long-Term Scenarios will compromise the accuracy of Long-Term Scenarios, shift costs to transmission customers that should be borne by interconnection customers, or create an incentive for additional interconnection requests that could slow down interconnection queue processing.[1045] We note that over the years, and recently with Order No. 2023, transmission providers and the Commission have adopted changes to generator interconnection procedures to reduce the submission of speculative interconnection requests in the interconnection queue. For example, interconnection requests require significant financial commitments from the interconnection customer (*e.g.,* application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023.[1046] Noting that, as discussed above, transmission providers will have discretion as to how they account for factors in Long-Term Scenarios and may determine whether certain generator interconnection requests are speculative and/or duplicative, such that the requests are unlikely to affect Long-Term Transmission Needs, and then make corresponding adjustments to their Long-Term Scenarios. As discussed in further detail below, transmission providers can also account for uncertainty by discounting or putting more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category. Additionally, we believe that the existence of a large number of interconnection requests in a certain area, even if some of those requests are speculative, indicates that generation developers have an interest in interconnecting resources in that area, which Long-Term Scenarios should take into account.

(g) Utility and Corporate Commitments and Federal, Federally-Recognized Tribal, State, and Local Policy Goals That Affect Long-Term Transmission Needs (Factor Category Seven)

(1) Comments

474. Some commenters generally support the proposed requirement to incorporate in Long-Term Scenarios utility and corporate commitments and Federal, state, and local goals that affect the future resource mix and demand.[1047] ACEG contends that FPA section 217(b)(4) supports the Commission's proposed requirement to include public policies and utility and corporate renewable procurement goals within Long-Term Scenarios because load-serving entities' service obligations will depend upon both public policies and the resource preferences of their customers.[1048] AEE highlights the role of local goals by noting that 29 of the 50 most populous cities in the United States have set clean or renewable energy targets.[1049]

475. Advanced Energy Buyers argue that private efforts to use more low- and zero-carbon electricity are significantly affecting the resource mix and in turn transmission needs, noting that since 2014, commercial and industrial customers have contracted for more than 52 GW of clean energy in the United States, with annual increases every year since 2016.[1050] Moreover, Advanced Energy Buyers state, corporate and industrial customer demand for renewable energy in the United States is expected to reach about 85 GW by 2030.[1051] Advanced Energy Buyers state that, in some markets, corporate demand is already a dominant driver of renewable energy deployment, as in Illinois, where corporate procurement accounted for roughly one-third of total renewable deployment.[1052] SEIA states that, for corporate commitments, transmission providers should include data from the Clean Energy Buyers Association Deal Tracker, and for utility commitments, transmission providers should include

[1041] Omaha Public Power Initial Comments at 3.

[1042] Dominion Reply Comments at 7–8.

[1043] PJM Market Monitor Initial Comments at 4.

[1044] MISO Initial Comments at 35–36.

[1045] Dominion Reply Comments at 7–8; Nebraska Commission Initial Comments at 4–5; Omaha Public Power Initial Comments at 3.

[1046] Order No. 2023, 184 FERC ¶ 61,054 at P 490.

[1047] ACEG Initial Comments at 26–29; AEE Initial Comments at 10–11; Advanced Energy Buyers Initial Comments at 5–6; Amazon Initial Comments at 3–4; Center for Biological Diversity Initial Comments at 9–12; Environmental Groups Supplemental Comments at 2; Ørsted Initial Comments at 7; Pacific Northwest State Agencies at Initial Comments at 14; PIOs Initial Comments at 18–19; SEIA Initial Comments at 10; SREA Initial Comments at 41–46; *see also* Environmental Groups Supplemental Comments at 2 (''The electric industry is undergoing a major transformation driven by consumer, utility, and corporate preferences, state public policies, and the cost competitiveness of renewable energy. The Commission's transmission planning and cost allocation standards must be up to the challenge of enabling this transition while ensuring the continued provision of reliable and affordable electricity at just and reasonable rates.'').

[1048] ACEG Initial Comments at 26–29.

[1049] AEE Initial Comments at 10–11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), *https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets*).

[1050] Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers Alliance, *State of the Market 2022, https://cebuyers.org/state-of-the-market/*).

[1051] *Id.* at 5–6 (citing Wood Mackenzie, *Corporates Usher in New Wave of US Wind and Solar Growth* (Aug. 2019), *https://www.woodmac.com/our-expertise/focus/Power--Renewables/corporates-usher-in-new-wave-of-u.s.-wind-and-solar-growth/*).

[1052] *Id.* at 6 (citing Advanced Energy Economy, *Adding it All Up for Voluntary Buyers of Renewable Energy* (Jan. 2021), *https://blog.advancedenergyunited.org/adding-it-all-up-for-voluntary-buyers-of-renewable-energy*; Microsoft, *Greener datacenters for a brighter future: Microsoft's commitment to renewable energy* (May 2016), *https://blogs.microsoft.com/on-the-issues/2016/05/19/greener-datacenters-brighter-future-microsofts-commitment-renewable-energy/*).

data from state resource plans and regulatory filings.[1053]

476. SREA and ACEG argue that the Commission should require transmission providers to incorporate utilities' generation planning announcements associated with net zero commitments and publicized utility resource plans, including SEC filings and public statements, into the development of Long-Term Scenarios.[1054] SREA contends that such a requirement would protect the interests of customers and generation developers because these announcements affect the marketplace.[1055] Breakthrough Energy suggests that utility targets and expected consumer demand should also be incorporated into the development of Long-Term Scenarios because actual demand is often higher than reflected in utility plans, which do not sufficiently incorporate corporate demand, including corporate buyer commitments.[1056]

477. LADWP, MISO, and NRECA support the inclusion of this category of factors as long as transmission providers are allowed to discount these factors in their analysis by assuming the goals or commitments may not be fully met.[1057] NRECA is concerned that factor category seven (utility and corporate commitments) carries a distinct risk of stranded transmission costs and therefore supports it being discounted.[1058] NRECA further states that it is concerned that stakeholders may try to use Long-Term Regional Transmission Planning to impose goals and commitments that lack the force of law.[1059] LADWP argues that the Commission should allow transmission planners to use discretion when identifying utility commitments and local goals.[1060] MISO is concerned about the inherent difficulty of modeling corporate commitments given the ambiguous nature of corporate footprints.[1061]

478. Several commenters oppose including utility and corporate commitments and/or Federal, state, and local goals as a category of factors in Long-Term Scenarios.[1062] For example, California Commission states that it is not clear what purpose would be served by requiring transmission providers to incorporate these commitments or goals into Long-Term Scenarios yet, at the same time, allowing them to discount such commitments or goals to account for their inherent uncertainty.[1063] New York TOs argue that corporate commitments are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider. Moreover, New York TOs state that, if a goal is not codified as a law, it is not clear that it is sufficiently solidified and supported to be included as a factor.[1064]

479. PJM argues that the NOPR proposal to include corporate commitments as a factor in Long-Term Scenarios is vague, inappropriate, and impractical, because even if PJM is able to develop a record of information in the expansive PJM footprint, this information will likely be incomplete. PJM argues that the burden to ensure that a transmission provider is aware of corporate commitments and goals should be on the corporation or another interested party.[1065]

480. Illinois Commission states that transmission planning criteria should not include vague terms such as ''corporate goals,'' which could mean multiple things and may already be accounted for.[1066] Alabama Commission states that corporate commitments and goals are not a sufficient basis for planning decisions as they are not law and accountability for achieving them is limited.[1067] Similarly, Pennsylvania Commission states that determinants for Long-Term Scenarios should not be based on speculative factors, arguing that factors that include Federal, state, and local laws and regulations that affect the future resource mix and demand are preferable to factors that include utility, corporate, Federal, state, and local goals or policies that have no enforcement mechanisms.[1068] PPL states that utility and corporate commitments are unlikely to be sufficiently firm or definitive to pass state siting review.[1069]

(2) Commission Determination

481. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Seven into the development of Long-Term Scenarios because the relevant commitments and goals represent known consumer preferences that have been, and will continue to be, key drivers of Long-Term Transmission Needs. We agree with commenters that argue that corporate demand for clean energy resources, as demonstrated by the volume of bilateral corporate contracts with renewable energy resources, is already a major driver of changes in the resource mix and demand and that corporate and industrial customer demand for clean energy is projected to increase. We believe that it is necessary for transmission providers to incorporate publicly announced utility commitments in the development of Long-Term Scenarios. Such commitments may be ignored or overlooked in retail-level regulatory proceedings, but they nevertheless may have an impact on future changes in the resource mix and demand that must be accounted for to ensure the development of plausible Long-Term Scenarios.

482. We modify the NOPR proposal for Factor Category Seven to include federally-recognized Tribal goals that affect the resource mix and demand because we are persuaded by commenters that argue that such factors have the same potential to affect Long-Term Transmission Needs as Federal, state, and local goals. We believe that federally-recognized Tribal goals should include publicly announced policy recommendations, such as energy vision reports.[1070] Further, as discussed under Additional Categories of Factors below, we recognize that energy equity and justice goals are potential factors within Factor Category Seven.

[1053] SEIA Initial Comments at 10 (citing Clean Energy Buyer Association, CEBA Deal Tracker, *https://cebuyers.org/deal-tracker/*; Sierra Club, *Check Out Where We Are Ready For 100%, https://www.sierraclub.org/climate-and-energy/map*).

[1054] ACEG Initial Comments at 28–29; SREA Initial Comments at 41–46.

[1055] SREA Initial Comments at 41–46.

[1056] Breakthrough Energy Initial Comments at 14–15.

[1057] LADWP Initial Comments at 3; MISO Initial Comments at 36; NRECA Initial Comments at 32–33.

[1058] NRECA Initial Comments at 32 (citing GDS Assocs., Report, at 12 (Aug. 17, 2022)).

[1059] *Id.* at 32–33.

[1060] LADWP Initial Comments at 3.

[1061] MISO Initial Comments at 36.

[1062] Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Duke Initial Comments at 13; New York TOs Initial Comments at 11–12; Pennsylvania Commission Initial Comments at 6.

[1063] California Commission Initial Comments at 20.

[1064] New York TOs Initial Comments at 11–12.

[1065] PJM Reply Comments at 37–38 (citing PJM Initial Comments at 68).

[1066] Illinois Commission Initial Comments at 7.

[1067] Alabama Commission Initial Comments at 6.

[1068] Pennsylvania Commission Initial Comments at 5–6.

[1069] PPL Initial Comments at 8.

[1070] *See, e.g.,* Columbia River Inter-Tribal Fish Comm'n, *Energy Vision for the Columbia River Basin* (Sept. 2022), *https://critfc.org/wp-content/uploads/2022/09/CRITFC-Energy-Vision-Full-Report.pdf*.

483. While Federal, federally-recognized Tribal, state, and local goals may not have the same durability and binding impact of laws and regulations, we believe that it is appropriate for transmission providers to account for such goals in Long-Term Scenarios because these goals represent known preferences of governmental entities that affect Long-Term Transmission Needs. Such goals may improve or diminish the prospects of deploying certain technologies. For example, as AEE explains, local governments representing some of the most populous cities in the United States have established goals to have their cities' loads served by clean or renewable energy.[1071]

484. We disagree with commenters that argue that transmission providers should not be required to incorporate utility and corporate commitments into the development of Long-Term Scenarios because they may not be significant enough to drive Long-Term Transmission Needs or that accountability for achieving commitments and goals is too limited for these factors to be considered sufficiently firm.[1072] We acknowledge that utility and corporate commitments and governmental goals may be more likely to change over the transmission planning horizon than factors in other required factor categories; however, we are not persuaded that these commitments and goals are so speculative, amorphous, or unreliable that they should not be incorporated into Long-Term Scenarios at all. We emphasize that transmission providers have discretion, as discussed above, in how to account for these factors in the development of Long-Term Scenarios, and we note, as discussed in further detail below, that transmission providers can account for the uncertainty associated with the achievement of these commitments and goals by using discounting or putting more weight on the effects of these factors on Long-Term Transmission Needs in each of the required Long-Term Scenarios. Similarly, transmission providers have discretion to determine how to account for commitments and goals in Long-Term Scenarios if the effects of particular commitments or goals conflict with, negate, or duplicate the effects of other factors.

(h) Additional Categories of Factors

(1) Comments on Energy Equity and Justice

485. Some commenters argue that the Commission should include equity and energy justice considerations in Long-Term Regional Transmission Planning.[1073] Grand Rapids NAACP, agreeing with NASEO, urges the Commission to expand factors considered in Long-Term Regional Transmission Planning to include energy equity and justice.[1074] Grand Rapids NAACP also states that transmission providers should be required to follow Federal, state, and local laws addressing the need for energy equity and justice.[1075] In concordance with PIOs, Grand Rapids NAACP urges the Commission to address equity in the transmission planning process because doing so would encourage competition and lower consumer costs.[1076] Finally, Grand Rapids NAACP urges the Commission to encourage transmission providers to develop metrics that advance economic equity and environmental justice by facilitating consideration of the impact of transmission infrastructure on disadvantaged communities.[1077]

486. US DOE asserts that energy justice considerations will form an integral part of transmission planning. Specifically, US DOE states that transmission planning can identify potential sources, sinks, and locations of transmission expansion facilities and that identifying locations where frontline communities and historically underserved communities have faced long-standing impacts may affect the future resource mix.[1078] NESCOE agrees with US DOE and argues that regional transmission planning processes should accommodate state efforts to advance equity and environmental justice concerns.[1079] New England for Offshore Wind argues that without a transparent and inclusive transmission planning process, regional transmission planning efforts will be at odds with state policy on environmental justice.[1080]

487. PIOs state that the Commission should be clear that Long-Term Regional Transmission Planning complies with and incorporates relevant aspects of applicable Federal, federally-recognized Tribal, state, and local environmental and energy justice policies—including future resource mix impacts, assignment of transmission benefits toward disadvantaged communities, and project selection.[1081]

488. CARE Coalition states that the Commission should consider issues of siting and the granting of permits that cause significant delays in construction of new transmission facilities.[1082] CARE Coalition emphasizes WE ACT's argument that a final order should ensure that transmission planners and states "are cognizant about siting and the potential harms of transmission development to environmental justice communities."[1083] Relatedly, CARE Coalition highlights NRECA's argument that rural and poorer areas are disproportionately burdened under the current regime because "siting decisions are primarily driven by technical and economic factors."[1084]

(2) Comments on Efficiency and Technology

489. NASEO argues that the Commission should expand its list of factors that transmission providers should include in Long-Term Regional Transmission Planning and Long-Term Scenarios to include increased energy efficiency of existing transmission lines, and the efficient use of existing rights of way.[1085] Invenergy suggests that the Commission expressly require consideration of advanced-stage merchant HVDC transmission as a factor in regional transmission planning scenarios.[1086] Invenergy highlights US DOE's proposal that transmission providers consider trends in the development of HVDC network technology, arguing, however, that such

[1071] AEE Initial Comments at 10–11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), *https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets*).

[1072] Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Illinois Commission Initial Comments at 7; New York TOs Initial Comments at 11–12; Pennsylvania Commission Initial Comments at 5–6; PJM Reply Comments at 37–38 (citing PJM Initial Comments at 68); PPL Initial Comments at 8.

[1073] *See, e.g.,* California Energy Commission Initial Comments at 2; City of New York Initial Comments at 9; Clean Energy Buyers Initial Comments at 8–9; Grand Rapids NAACP Initial Comments at 12, 15, 21, 23; Grand Rapids NAACP Reply Comments at 2–3, 5; Montclair Congregation Supplemental Comments at 1; NARUC Initial Comments at 3–4; NASEO Initial Comments at 5; PIOs Initial Comments at 35–36; PIOs Reply Comments at 15; Policy Integrity Initial Comments at 28; WE ACT Initial Comments at 4–6.

[1074] Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

[1075] *Id.*

[1076] *Id.* (citing PIOs Initial Comments at 35, 36).

[1077] *Id.* at 2–3 (citing NARUC Initial Comments at 3–4).

[1078] US DOE Initial Comments at 9.

[1079] NESCOE Reply Comments at 8–9.

[1080] New England for Offshore Wind Initial Comments at 5.

[1081] PIOs Reply Comments at 15 (citing Grand Rapids NAACP Initial Comments at 12–15, 21–23 (listing notable Federal, state, and local public policies requiring that equity and energy justice inform decision making processes); WE ACT Initial Comments at 6).

[1082] CARE Coalition Reply Comments at 3.

[1083] *Id.* at 4 (citing WE ACT Initial Comments at 6).

[1084] *Id.* (citing NRECA Initial Comments at 39 n.111).

[1085] NASEO Initial Comments at 5.

[1086] Invenergy Initial Comments at 6–7.

consideration should include incorporating and accounting for HVDC transmission facilities in transmission planning models and scenarios.[1087]

(3) Comments Regarding Enhanced Reliability and Interregional Transfer Capability

490. PJM recommends that the Commission require enhanced reliability and Interregional Transfer Capability as two additional categories of factors that transmission providers must incorporate into the development of Long-Term Scenarios.[1088] PJM envisions enhanced reliability to include, but not be limited to, storm hardening of critical facilities, reducing the number of critical CIP–014 facilities through transmission upgrades, coordination of infrastructure development with natural gas pipelines serving generation in the region, and ensuring redundancy of facilities, where appropriate, to address the threat of physical or cyber attacks.[1089] PJM envisions Interregional Transfer Capability to be established in accordance with the methodology that the Commission adopts in a subsequent order.[1090]

491. Invenergy agrees with the additional categories of factors that PJM proposes.[1091] ELCON supports the consideration of transfer capability between seams, which it asserts would provide transmission providers with the ability to develop and consider solutions that may solve for multiple drivers and offer greater benefits to more consumers.[1092] In contrast, AEE states that it disagrees with the additional categories of factors that PJM proposes, although it agrees with PJM that enhanced reliability planning is an important consideration.[1093]

(4) Commission Determination

492. We recognize that some commenters ask the Commission to require transmission providers to incorporate several categories of factors in addition to those proposed in the NOPR in the development of Long-Term Scenarios. We decline to include energy equity and justice as a distinct and additional category of factors because we believe that these important energy equity and justice laws and regulations, or goals, that are likely to affect Long-Term Transmission Needs, are accounted for in Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, or Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[1094] Stakeholders will have a meaningful opportunity to identify any such factors as part of the open and transparent stakeholder process described below in the Stakeholder Process and Transparency section.

493. We decline to adopt Invenergy's recommendation that the Commission require transmission providers to include advanced-stage merchant HVDC transmission as an additional category of factors. The Commission did not propose specific requirements in the NOPR regarding merchant HVDC transmission facilities under development, and we are not persuaded by the evidence in the record that the Commission should include advanced-stage HVDC transmission facilities in the minimum set of known determinants of Long-Term Transmission Needs. We reiterate that transmission providers may be aware of additional categories of factors beyond those adopted in this final order that drive Long-Term Transmission Needs and may incorporate additional categories of factors in the development of Long-Term Scenarios provided that each Long-Term Scenario remains plausible.

494. In response to PJM's request for the Commission to require enhanced reliability and Interregional Transfer Capability[1095] as additional categories of factors,[1096] we find that the record in this proceeding is insufficient to adequately consider whether to require transmission providers to adopt such categories of factors in this final order. As noted in our response to Invenergy just above, transmission providers may incorporate additional categories of factors in the development of Long-Term Scenarios provided that each Long-Term Scenario remains plausible. We note that, in this final order, we provide transmission providers with flexibility in how they develop Long-Term Scenarios to identify Long-Term Transmission Needs. We believe that other parts of this final order enable transmission providers to account for enhanced reliability and Interregional Transfer Capability by modeling sensitivities and using certain transmission benefits. As discussed below, we require transmission providers to develop at least one sensitivity analysis, applied to each Long-Term Scenario, to account for uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area that determine the benefits of or need for Long-Term Regional Transmission Facilities. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to measure, and consider as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide.

c. Treatment of Specific Categories of Factors

i. NOPR Proposal

495. The Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning incorporate and be consistent with Federal, state, and local laws and regulations that affect the future resource mix and demand; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load-serving entities. The Commission preliminarily found that it is reasonable to require transmission providers to assume that legally binding obligations and state utility regulator-approved plans will be followed and that expected supply obligations for load-serving entities will be fully met. As a result, the Commission explained that, under the proposal, transmission providers cannot discount the factors included in the categories of Federal, state, and local laws and regulations that affect the future resource mix; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected

[1087] Invenergy Reply Comments at 11 (citing US DOE Initial Comments at 13).

[1088] PJM Initial Comments at 6, 13, 65–67.

[1089] *Id.* at 66.

[1090] *Id.* at 66–67.

[1091] Invenergy Reply Comments at 11.

[1092] ELCON Initial Comments at 8.

[1093] AEE Reply Comments at 20.

[1094] Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

[1095] We define Interregional Transfer Capability for purposes of this final order consistent with the definition of total transfer capability in the Commission's regulations as: ''the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.'' 18 CFR 37.6(b)(1)(vi). In the context of Interregional Transfer Capability, an ''area'' in the above definition would be a transmission planning region composed of transmission providers.

[1096] PJM Initial Comments at 6, 13, 65–67.

supply obligations for load-serving entities.[1097]

496. In addition, the Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning include trends in technology and fuel costs within and outside the electricity supply industry, including shifts toward electrification of buildings and transportation; resource retirements; and generator interconnection requests and withdrawals. For these particular categories of factors, the Commission proposed to provide transmission providers with flexibility in how they incorporate each factor into Long-Term Scenarios as long as transmission providers identify and publish specific factors for each of these categories, as further described below.[1098]

497. Further, the Commission proposed to require that each Long-Term Scenario incorporate utility and corporate goals and Federal, state, and local goals that affect the future resource mix and demand. However, the Commission acknowledged that these categories of factors are less binding and more likely to change over time, and therefore their impact on the future resource mix and demand are less certain, than other categories of factors. For this reason, the Commission preliminarily found that it may be appropriate for transmission providers to discount such goals to account for this uncertainty. The Commission explained that transmission providers would not be required to assume that utility and corporate goals and Federal, state, and local goals that affect the future resource mix will be fully met.[1099]

ii. Comments

498. Several commenters, that generally support the NOPR proposal, support discounting and rebut arguments opposing discounting.[1100] NRECA, Exelon, and TAPS argue that the NOPR proposal to allow transmission providers to discount some categories of factors while weighing factors in other categories more heavily strikes an appropriate balance.[1101] Specifically, Exelon supports the NOPR proposal to allow for variation in the treatment of different categories of factors such as legislated energy policy, which it states should not vary by scenario, and non-binding targets, which it states may be discounted yet are important to consider.[1102] TAPS also supports the proposed flexibility in how transmission providers incorporate factors that are not Federal, state, and local laws and regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities.[1103]

499. Some commenters express concerns that the NOPR proposal would allow transmission providers in each transmission planning region to discount, or not fully incorporate, some factors when developing Long-Term Scenarios.[1104] Clean Energy Associations state that certain factors (*i.e.,* Federal, state, and local policies, utility integrated resource plans, generator retirements, interconnection requests, corporate commitments, and trends in technology and fuel costs) can be quantified and should be reflected in Long-Term Scenarios without discounting.[1105] Clean Energy Buyers are concerned that the flexibility proposed in the NOPR for transmission providers to incorporate into their Long-Term Scenarios the categories of factors that include trends in fuel costs and technologies both inside and outside the electricity supply industry, including regarding shifts in electrification of transport and buildings, resource retirements, and generator interconnection requests and withdrawals, could delay the transmission build-out.[1106] ACEG recommends that the Commission presume that all factors are required to be incorporated (and not discounted or only considered) unless the Commission approves a request from the transmission providers in a transmission planning region not to include a factor.[1107] In response, California Municipal Utilities argue that mandating the use of specific factors would not account for the cost consequences of such mandates, which must be considered for any transmission planning requirements to be just and reasonable.[1108]

500. Several commenters object to the Commission's proposal to provide transmission providers with the flexibility to discount utility and corporate and Federal, state, and local goals that affect the future resource mix and demand.[1109] Amazon states that transmission providers should not be allowed to discount clean energy goals in their development of Long-Term Scenarios without proving such discounting is just and reasonable by showing evidence that such goals have been unfulfilled in the past, or that those goals have been altered or abandoned.[1110]

501. PIOs state that the NOPR proposal to discount Factor Category Seven would allow transmission providers to game the results if their incentives are contrary to consumers' goals.[1111] SEIA urges the Commission to limit the flexibility given to transmission providers regarding this factor because SEIA believes that they would ignore certain factors if consideration is not mandatory.[1112] Further, Clean Energy Associations argue that utility, corporate, and Federal, state, and local goals should be fully incorporated, without discounting targets not enshrined in law or regulation. If necessary, Clean Energy Associations contend, changes in non-binding obligations could be treated as a sensitivity or probabilistic change in one or more scenarios to determine how they might affect transmission development.[1113]

502. PIOs state that, when utilities make commitments affecting the future resource mix and consumer demand, they should be held to them and that granting transmission providers complete discretion to discount such factors could undermine the goals of the NOPR proposal. Thus, PIOs state, the Commission should set minimum requirements for some factors, including for incorporating corporate commitments into future resource mix estimates.[1114] PIOs assert that widespread support exists for these

[1097] NOPR, 179 FERC ¶ 61,028 at P 106.

[1098] *Id.* P 107.

[1099] *Id.* P 108.

[1100] Exelon Initial Comments at 10–11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7; NRECA Initial Comments at 32; TAPS Initial Comments at 2–3, 8.

[1101] Exelon Initial Comments at 10–11; NRECA Initial Comments at 32; TAPS Initial Comments at 2–3, 8.

[1102] Exelon Initial Comments at 10–11.

[1103] TAPS Initial Comments at 2–3, 8.

[1104] ACEG Initial Comments at 27–28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 23–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8–10.

[1105] Clean Energy Associations Initial Comments at 10–11.

[1106] Clean Energy Buyers Initial Comments at 15–16.

[1107] ACEG Initial Comments at 27.

[1108] California Municipal Utilities Reply Comments at 5–6.

[1109] Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 24–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8.

[1110] Amazon Initial Comments at 4.

[1111] PIOs Initial Comments at 18–19.

[1112] SEIA Initial Comments at 8.

[1113] Clean Energy Associations Initial Comments at 10–11.

[1114] PIOs Initial Comments at 17–18.

recommendations, citing ELCON as an example.[1115]

503. Pine Gate argues that transmission providers should be required to assume that utility and corporate and Federal, state, and local goals that affect the future resource mix will be fully met in at least one of their Long-Term Scenarios.[1116]

504. In addition, Pattern Energy argues that the Commission should distinguish between generation assumptions and demand assumptions for purposes of 20-year transmission planning so that there is no ambiguity. For example, Pattern Energy states that transmission providers should not be permitted to utilize their planning for load growth to satisfy the requirement to plan for changing resources and demand. Pattern Energy asserts that transmission providers should be required to distinguish between modeling a changing resource mix and, separately, a changing demand profile, arguing that both are important and should be considerations in near-term and long-term transmission planning.[1117]

505. NYISO argues that the final order should permit transmission providers to appropriately account for, in coordination with state and local entities and stakeholders, the likely effect of applicable laws and regulations on the need for transmission and to realistically appraise achievement of such laws and regulations.[1118]

506. Some commenters oppose the NOPR proposal to require that transmission providers incorporate applicable local laws and regulations in their development of Long-Term Scenarios.[1119] Duke explains that although local laws and regulations for decarbonization and electrification may affect the resource mix and demand at the local level, it is unclear how such laws would have a material effect on regional transmission planning that warrants the additional burden of tracking and incorporating them into Long-Term Scenarios.[1120] Alabama Commission argues that local laws, regulations, and goals might change or conflict with the policy perspectives of other states.[1121] PPL claims that the NOPR proposal is impractical and will significantly increase uncertainty, which in turn will invite disagreement and litigation.[1122] PJM recommends that the Commission require transmission providers to only consider local laws, local regulations, and local goals to the extent that such laws, regulations, and goals are brought to their attention by states, other local regulators, or stakeholders.[1123]

iii. Commission Determination

(a) Treatment of Factors in the First Three Categories

507. With regard to the first three categories of factors,[1124] we require transmission providers in each transmission planning region to assume that legally binding obligations (*i.e.,* Federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met. Therefore, we require that each Long-Term Scenario account for and be consistent with, and not discount, factors in the first three categories of factors once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs. We believe it is necessary to prohibit discounting of factors in the first three categories of factors because they are more certain drivers of Long-Term Transmission Needs, relative to factors in other factor categories.

508. We clarify that transmission providers may rely on the open and transparent stakeholder process discussed below to identify the factors in the first three required categories of factors. More specifically, this final order does not obligate transmission providers to independently identify all of the factors in the first three categories of factors. We believe that it would be unduly burdensome and potentially impractical for transmission providers to independently identify all of the potential factors in the first three categories of factors, which will include numerous Federal, federally-recognized Tribal, state, and local laws and regulations, as well as integrated resource plans and expected supply obligations for load-serving entities.[1125] However, transmission providers may, if they choose, independently identify factors in the first three categories of factors as part of the stakeholder process, discussed further in the Stakeholder Process and Transparency section below.

509. We believe that this clarification addresses PJM's request that we clarify that the burden of making the transmission provider aware of laws, regulations, and goals rests with stakeholders and not with the transmission provider itself.[1126] We also believe that this clarification mitigates the potential administrative burdens and compliance risks identified by ISO–NE, as well as the burden of incorporating factors identified by SPP.[1127]

510. In addition, as clarified above, transmission providers retain the discretion to determine whether particular factors, including those in the first three categories of factors, that stakeholders identify are likely to affect Long-Term Transmission Needs. Thus, transmission providers may determine, for example, that some stakeholder-identified local laws and regulations that fall within Factor Categories One and Two are unlikely to affect Long-Term Transmission Needs and therefore need not be accounted for in the development of Long-Term Scenarios. We believe that this clarification addresses concerns about the additional burden some commenters identified of tracking and incorporating local laws and regulations into the development of Long-Term Scenarios, as well as concerns that the inclusion of local laws and regulations in the first two categories of factors creates a burden for transmission providers to account for factors that are unlikely to affect Long-Term Transmission Needs.[1128]

511. We believe that the open and transparent stakeholder process

[1115] PIOs Reply Comments at 10–11 (citing ELCON Initial Comments at 4).

[1116] Pine Gate Initial Comments at 25.

[1117] Pattern Energy Initial Comments at 26.

[1118] NYISO Initial Comments at 23.

[1119] Alabama Commission Initial Comments at 5–6; Ameren Initial Comments at 9–10; Duke Initial Comments at 13–14, 16; ISO–NE Initial Comments at 26–27; ISO/RTO Council Initial Comments at 4–5; NYISO Initial Comments at 21–23.

[1120] Duke Initial Comments at 13.

[1121] Alabama Commission Initial Comments at 5–6.

[1122] PPL Initial Comments at 7–8.

[1123] PJM Reply Comments at 38 (citing PJM Initial Comments at 68).

[1124] As explained above, the first three categories of factors are: (1) Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; and (3) state-approved integrated resource plans and expected supply obligations for load-serving entities.

[1125] The Commission has previously found that transmission providers ''cannot later be faulted'' for failing to consider projections of a need for service from a point-to-point transmission customer if such projections are not provided by the transmission customer. Order No. 890, 118 FERC ¶ 61,119 at P 487; *id.* (''We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points . . . . If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests.'').

[1126] PJM Initial Comments at 68.

[1127] ISO–NE Initial Comments at 26–27; SPP Initial Comments at 7–8.

[1128] Duke Initial Comments at 13.

discussed below in the Stakeholder Process and Transparency section will help transmission providers to ensure that each Long-Term Scenario accounts for factors in the first three categories of factors without discounting the effects of those factors on Long-Term Transmission Needs. We expect that transmission providers will rely, at least in part, on information that relevant Federal, state, and local government entities, federally-recognized Tribes, utilities, and load-serving entities provide during the required open and transparent stakeholder process to determine if specific factors are likely to affect Long-Term Transmission Needs and how to account for those specific factors in Long-Term Scenarios. We agree with NYISO regarding the value of coordination and clarify that transmission providers may work in coordination with government entities and stakeholders to determine how applicable laws and regulations may affect Long-Term Transmission Needs.[1129]

512. We recognize that some commenters raise concerns as to whether factors in the first three categories of factors can be fully achieved (*e.g.,* a legislative requirement is met) or may have various levels of impact on Long-Term Transmission Needs.[1130] At the outset, we find it appropriate to assume legally binding obligations are met, unless and until there is a change in law. Government entities have an interest and ability to ensure that the requirements of laws and regulations are fully achieved. Similarly, utilities and load-serving entities, as well as the relevant retail regulator, have an interest in developing accurate integrated resource plans and expected supply obligations that can be fully achieved. Even in the limited circumstances in which these factors are not fully achieved, we expect the targets or requirements associated with these factors will be informative for purposes of identifying Long-Term Transmission Needs. We acknowledge that, for certain factors, there may be insufficient information for transmission providers to determine, or stakeholder disagreement about, how the factor will affect Long-Term Transmission Needs. In such instances, we clarify that transmission providers have discretion over how to account for a factor in the first three categories of factors in their Long-Term Scenarios as long as the assumptions in each Long-Term Scenario are consistent with legally binding obligations, state-approved integrated resource plans, and expected supply obligations of load-serving entities.

513. For example, when a legally binding obligation sets a minimum requirement or threshold (*e.g.,* a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030), transmission providers may develop Long-Term Scenarios assuming either the minimum amount of the requirement or more than the minimum amount of the requirement (*e.g.,* modeling 10 gigawatts of electric storage resources deployed by 2030 instead of the minimum 5 gigawatts) but may not develop any Long-Term Scenarios that are inconsistent with that minimum (*e.g.,* modeling only 2 gigawatts of electric storage resources deployed by 2030). We believe that these clarifications sufficiently address PPL's concerns regarding the uncertainty associated with how transmission providers are expected to translate factors, including local laws and regulations, into Long-Term Scenarios.[1131] We note that the requirement, discussed further below, that Long-Term Scenarios be plausible and diverse also clarifies how transmission providers must account for factors in the Long-Term Scenarios. That is, while transmission providers can model assumptions that exceed the minimum requirements of factors in the first three categories in developing Long-Term Scenarios, they can only exceed those minimum requirements such that each Long-Term Scenario remains plausible.[1132] Similarly, the requirement that Long-Term Scenarios be diverse ensures that transmission providers will model the effect of factors on Long Term Transmission Needs in different ways, and thus that Long-Term Scenarios help to manage uncertainty over how factors will affect Long-Term Transmission Needs.

514. We disagree with ISO–NE's claim that requiring that each Long-Term Scenario account for and consistently reflect the first three categories of factors would unnecessarily prevent testing of variations with these categories of factors. Where a factor's effect is not clear on its face, transmission providers have discretion, within reason, to determine the likely effect of full achievement of the factor and reflect that into development of the Long-Term Scenarios. Transmission providers also are not limited to assuming only the minimum requirements of a factor are fully achieved in developing the Long-Term Scenarios.

515. We also are unpersuaded by commenter claims that local laws and regulations might conflict with state laws and regulations and, therefore, we should not include local laws and regulations in the first two categories of factors.[1133] However, we acknowledge that there may be limited circumstances when two legally binding factors have conflicting or opposite implications for Long-Term Transmission Needs. We clarify that, in such circumstances, transmission providers shall reconcile this information while giving full effect to the maximum extent possible to all legally binding factors. For example, where two laws have equal and opposite effect, transmission providers may need to incorporate them as negating each other, as necessary to comply with the requirement to produce plausible Long-Term Scenarios. In circumstances when that is not possible because the legally binding factors support alternatives to the same assumption used to develop Long-Term Scenarios, transmission providers could use two or more of the three required Long-Term Scenarios, or develop additional Long-Term Scenarios, to capture the differences implied by each of the conflicting factors.

(b) Treatment of Factors in the Last Four Categories

516. We affirm that transmission providers have additional discretion in how they account for each factor in the last four categories of factors compared to how they account for each factor in the first three categories.[1134] After transmission providers have determined that a specific factor, stakeholder-identified or otherwise, is likely to affect Long-Term Transmission Needs over the transmission planning horizon, transmission providers must then assess the extent to which the anticipated effects on Long-Term Transmission Needs due to that factor are likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. For example, for a corporate commitment

[1129] NYISO Initial Comments at 23.

[1130] *Id.*

[1131] PPL Initial Comments at 8.

[1132] Likewise, as discussed in the Treatment of Factors in the Last Four Categories section, transmission providers may only discount the effect of factors in the last four categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

[1133] Alabama Commission Initial Comments at 5–6; PJM Initial Comments at 68.

[1134] As explained above, the last four categories of factors are: (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; (7) utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.

identified in Factor Category Seven, transmission providers can make a determination that only a fraction of that corporate commitment will actually be met, and the transmission providers can subsequently model more limited effects on Long-Term Transmission Needs due to that factor, in some or all Long-Term Scenarios. Likewise, transmission providers may put more weight on the factor by modeling more than the projected change in some or all Long-Term Scenarios to reflect the transmission providers' view regarding the likelihood that the anticipated effects on Long-Term Transmission Needs due to that factor will occur. Transmission providers may choose to discount or put more weight on the effects on Long-Term Transmission Needs due to factors in Factor Categories Four through Seven to account for uncertainty when developing plausible and diverse Long-Term Scenarios.

517. Several commenters generally support this flexibility to treat the last four categories of factors differently from the first three.[1135] We believe that requiring transmission providers to incorporate the last four categories of factors, but allowing transmission providers to discount the effects of factors within these categories, strikes an appropriate balance between requiring factors in these categories be given full weight, and allowing them to be excluded entirely in developing Long-Term Scenarios. We believe that these categories of factors affect Long-Term Transmission Needs, and absent a requirement to incorporate them, transmission providers may fail to identify, evaluate, and select more efficient or cost-effective Long-Term Regional Transmission Facilities to address those Long-Term Transmission Needs. On the other hand, these categories of factors are less certain than the first three categories and should not necessarily be given the same weight in developing Long-Term Scenarios as factors that are legally binding.

518. We disagree with the concern that this flexibility could allow transmission providers to ignore the last four factor categories[1136] because the final order requires transmission providers to incorporate all categories of factors in each Long-Term Scenario, even if they discount specific factors within the category, and requires that all Long-Term Scenarios be plausible.[1137] We reiterate that transmission providers may only discount the effects of factors in these categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

d. Stakeholder Process and Transparency

i. NOPR Proposal

519. The Commission proposed to require that transmission providers identify and publish on an Open Access Same-Time Information System (OASIS) or other public website a list of the factors that fall into each of the required categories of factors that they will incorporate in their development of Long-Term Scenarios. The Commission explained that transmission providers would be responsible for identifying all the factors they know of and are considering incorporating in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission also proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors that transmission providers must incorporate in their development of Long-Term Scenarios, such as specific laws, regulations, goals, and commitments, and to provide input on how to appropriately discount factors that are less certain.[1138]

520. The Commission noted that, under Order No. 1000, transmission providers must already have procedures in their OATTs that give stakeholders a meaningful opportunity to submit proposed transmission needs driven by Public Policy Requirements and that allow transmission providers to identify, out of the larger set of potential transmission needs driven by Public Policy Requirements that stakeholders propose, those needs for which transmission facilities will be evaluated.[1139] Therefore, the Commission explained that transmission providers may be able to modify and expand these existing procedures for identifying transmission needs driven by Public Policy Requirements to meet these proposed requirements regarding the identification of factors for incorporation into Long-Term Scenarios.[1140]

ii. Comments

(a) State Input

521. Several commenters emphasize the important role of stakeholders, including states, in identifying or commenting on the factors to be included in the development of Long-Term Scenarios.[1141] In addition, Southeast PIOs note that states do not currently engage in regional transmission planning processes to any meaningful degree, and therefore, the Commission should encourage their participation in shaping and conducting Long-Term Regional Transmission Planning.[1142]

522. Some commenters discuss the important role of states in identifying factors within specific category of factors.[1143] DC and MD Offices of People's Counsel assert that the final order should explicitly require information on the factors to be provided by appropriate authorities, such as state agencies.[1144] New Jersey Commission supports the Commission's proposal to require that states have a meaningful opportunity to propose potential factors to be incorporated into the development of Long-Term Scenarios and to provide input on appropriately discounting less certain factors.[1145] NESCOE asserts that, if states do not play a central role in determining the factors, the proposed reforms will likely run into the problem that underlies the Order No. 1000 public policy transmission planning process in New England, where states do not have a decision-making role over project selection even though state laws or policies could be the driver for the project.[1146]

523. However, other commenters state that their existing processes are adequate for determining the relevant factors to include in Long-Term

[1135] APPA Initial Comments at 27–28; Exelon Initial Comments at 10–11 (citing NOPR, 179 FERC ¶ 61,028 at P 121); NRECA Initial Comments at 29–32; TAPS Initial Comments at 2–3, 8.

[1136] *E.g.,* ACEG Initial Comments at 27–28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 23–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8–10.

[1137] ACEG Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 11.

[1138] NOPR, 179 FERC ¶ 61,028 at P 109.

[1139] *Id.* P 110 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 206–207; Order No. 1000–A, 139 FERC ¶ 61,132 at P 335).

[1140] *Id.*

[1141] APPA Initial Comments at 27–29; PIOs Initial Comments at 22; PJM Initial Comments at 70; Southeast PIOs Initial Comments at 45, 46–47.

[1142] Southeast PIOs Initial Comments at 45–46; State Officials Supplemental Comments at 1.

[1143] DC and MD Offices of People's Counsel Initial Comments at 12; New Jersey Commission Initial Comments at 14–15.

[1144] DC and MD Offices of People's Counsel Initial Comments at 12.

[1145] New Jersey Commission Initial Comments at 14–15.

[1146] NESCOE Initial Comments at 28–29.

Regional Transmission Planning.[1147] PJM states that it currently has processes and standing committees that allow states and stakeholders to participate in discussions of factors to use in its transmission planning processes. For example, PJM asserts that its Independent State Agencies Committee is set up to receive feedback on transmission planning from states, and it discusses, among other things, assumptions used in the models, relevant regulatory initiatives and their impact, and alternative sensitivities, as well as what was discussed at other committee meetings. In addition, PJM states, it vets all proposed transmission solutions with its Transmission Expansion Advisory Committee before submitting them to the PJM board for approval.[1148]

(b) Transparency, Enforcement, and Accuracy

524. Cross Sector Representatives state that Long-Term Regional Transmission Planning processes should provide transparency for impacted stakeholders.[1149] SEIA argues that the Commission should adopt clear, uniform language that sets forth the specific goals and deliverables from the proposed Long-Term Regional Transmission Planning process for transmission providers to include in their tariffs, including language that mirrors the proposed list of categories of factors the Commission included in the NOPR.[1150]

525. Several commenters support the NOPR proposal to require transmission providers to post the list of factors that they will incorporate into their Long-Term Scenarios on a public website for stakeholder comment.[1151] Pine Gate recommends that the Commission further require that transmission providers identify and publish all factors that were considered but not incorporated.[1152]

526. Clean Energy Buyers state that, to ensure transparency and just and reasonable rates, the Commission should require that transmission providers post the details regarding any proposed or adopted discounting of factors on OASIS, including: (1) which factors are to be discounted; (2) the extent of the discounting; and (3) the justification for and derivation of the amount of discounting deemed appropriate.[1153]

527. GridLab and R Street propose modifications to the NOPR proposal regarding the role of stakeholders.[1154] GridLab proposes that state agencies, other stakeholders, and independent experts could play a dominant role in enforcing the Commission's requirement to incorporate specific categories of factors, and that the Commission would provide a common framework establishing guidelines on the kinds of factors that transmission providers should consider, at a minimum, in developing Long-Term Scenarios.[1155] In addition, R Street argues that governance mechanisms should drive the selection of data sets, methods, and assumptions behind these factors to promote objective accuracy.[1156]

iii. Commission Determination

528. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios.[1157] As discussed below, we also adopt the NOPR proposal, with modification, to require transmission providers to publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of those factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.

529. We believe that a robust stakeholder process will ensure that transmission providers can identify which, and how, specific factors might influence Long-Term Transmission Needs over the transmission planning horizon. For this reason, consistent with Order No. 890's transmission planning principles,[1158] we require transmission providers to give stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate in Long-Term Scenarios, including how to account for a specific factor in terms of how the factor may affect Long-Term Transmission Needs. We clarify that this meaningful opportunity for stakeholders to provide timely input includes the opportunity to propose factors, provide information and identify sources of best available data, propose how a factor may affect Long-Term Transmission Needs, and explain how that factor could be reflected in the development of Long-Term Scenarios, including the extent to which it is appropriate to discount the effects of certain factors on Long-Term Transmission Needs. We note that some transmission providers have existing processes in place that allow states and stakeholders to participate in discussions of factors, which transmission providers can propose, with any necessary modifications, to comply with this final order.[1159]

530. We believe that affording stakeholders a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios will help transmission providers to develop more accurate assumptions to serve as the basis for their Long-Term Scenarios. Specifically, with stakeholder input, transmission providers will be in a better position to determine which specific factors within each category of factors they should account for in the development of Long-Term Scenarios, as well as how best to incorporate them. Stakeholder input is particularly important for factors in the first three categories of factors because Federal, state, and local government entities, federally-recognized Tribes, and utilities, load-serving entities, and their retail regulators that participate in the stakeholder process are distinctly

[1147] MISO Initial Comments at 34–35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6; PJM Initial Comments at 6, 64, 70–71.

[1148] PJM Initial Comments at 70–71.

[1149] Cross Sector Representatives Supplemental Comments at 1.

[1150] SEIA Reply Comments at 3–4 (citing PJM Initial Comments at 27–28).

[1151] Ameren Initial Comments at 11–12; APPA Initial Comments at 28; NESCOE Initial Comments at 28; Pine Gate Initial Comments at 25; PIOs Initial Comments at 22.

[1152] Pine Gate Initial Comments at 25.

[1153] Clean Energy Buyers Initial Comments at 16–17.

[1154] GridLab Initial Comments at 20–21; R Street Initial Comments at 7.

[1155] GridLab Initial Comments at 21.

[1156] R Street Initial Comments at 7.

[1157] As an example, transmission providers would provide stakeholders with an opportunity to describe how a specific state law in the first category of factors will result in the development of new resources of a certain type, the retirement of existing resources, or changes in demand patterns due to increased electrification.

[1158] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 454.

[1159] MISO Initial Comments at 34–35; PJM Initial Comments at 6, 64, 70–71.

positioned to provide transmission providers with vital information on how the factors over which they have authority or govern are likely to influence Long-Term Transmission Needs over the transmission planning horizon. Similarly, utilities, corporations, and governments that participate in the stakeholder process are distinctly positioned to provide transmission providers with vital information regarding factors in Factor Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs. The required stakeholder process ensures that all stakeholders, including states, can provide important and useful information concerning factors that they believe will affect Long-Term Transmission Needs.

531. We recognize that different stakeholders may provide information about the same factor that is contradictory—an issue identified by some commenters.[1160] Different stakeholders may also provide different analyses showing, for example, how a specific factor will affect resource additions and retirements. However, as we explain earlier, transmission providers have discretion regarding how to account for specific factors in their development of Long-Term Scenarios. In reviewing the information provided by stakeholders in the open and transparent stakeholder process, transmission providers may weigh more heavily one source of information over another. To maintain transparency for stakeholders, transmission providers must include a general statement explaining how they will account for each factor in their Long-Term Scenarios on the public portion of an OASIS or other public website, as further described below.

532. We also believe that the information provided in the open and transparent stakeholder process will reduce the burden placed on transmission providers to identify and assess the impact of relevant factors for each category. For example, transmission providers can rely on the open and transparent stakeholder process to identify the multiple relevant local laws and regulations that are likely to influence Long-Term Transmission Needs over the transmission planning horizon. The same is true for the utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs in Factor Category Seven. During the stakeholder process, government entities, utilities, and corporate entities can identify their publicly announced goals and provide feedback on how the transmission providers can account for these publicly announced goals in Long-Term Scenarios. These entities will have an opportunity to provide information to help the transmission providers determine the likelihood that they will achieve their stated goals, which the transmission providers can then use to discount the specific factors in Factor Category Seven, if necessary.

533. With regard to the information about factors and categories of factors that transmission providers must publish on the public portion of an OASIS or other public website, we modify the proposal in the NOPR. We require transmission providers to publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of these factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.[1161] Transmission providers must post this information after stakeholders, including states, have had the meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.

534. We believe that this transparency is necessary to make clear to stakeholders which specific factors transmission providers incorporate into Long-Term Scenarios and how they incorporate those factors. We believe the posting requirement will also provide greater transparency into how transmission providers develop Long-Term Scenarios (discussed below), as some commenters requested, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors.

535. In response to commenters requesting additional transparency,[1162] we require transmission providers to publish on the public portion of an OASIS or other public website the factors that were considered but not accounted for in the development of Long-Term Scenarios. We believe this requirement will help stakeholders understand which factors, either identified in the stakeholder process or independently identified by a transmission provider, the transmission providers in a transmission planning region have determined are unlikely to affect Long-Term Transmission Needs. This transparency also ensures that stakeholder-proposed factors are reviewed in a fair and non-discriminatory manner.

536. We decline to require transmission providers to publicly publish the justification for and derivation of the amount of discounting deemed appropriate, as requested by Clean Energy Buyers.[1163] We believe such a requirement to detail the rationale for the treatment of each factor in Factor Categories Four through Seven, across all Long-Term Scenarios, would create a time-consuming administrative burden for transmission providers that is not justified by the value of the additional information provided to stakeholders.

537. We decline to adopt modifications to the NOPR proposal that would diminish the role of the transmission providers in developing Long-Term Scenarios.[1164] Transmission providers must provide stakeholders with a meaningful opportunity to propose potential factors and to provide input on how to incorporate specific factors in the development of Long-Term Scenarios, as described above. However, we reiterate that transmission providers are not required to incorporate stakeholder-identified factors into their development of Long-Term Scenarios merely because stakeholders propose them, if transmission providers determine that the factor is unlikely to influence Long-Term Transmission Needs over the transmission planning horizon. Consistent with Order No. 890, the ultimate responsibility for transmission planning remains with the transmission provider.[1165]

[1160] *E.g.,* Undersigned States Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 106).

[1161] As discussed above, transmission providers may not discount factors in Factor Categories One through Three.

[1162] *E.g.,* Pine Gate Initial Comments at 25.

[1163] Clean Energy Buyers Initial Comments at 16–17.

[1164] *E.g.,* GridLab Initial Comments at 20–21; R Street Initial Comments at 7.

[1165] Order No. 890, 118 FERC ¶ 61,119 at P 454. There, in response to the suggestion by some commenters that we require transmission providers

Continued

4. Number and Development of Long-Term Scenarios

a. NOPR Proposal

538. In the NOPR, the Commission proposed to require transmission providers to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning at least once during a transmission planning cycle.[1166] The Commission explained that it preliminarily found that using at least four distinct Long-Term Scenarios is a reasonable lower bound for the number of Long-Term Scenarios that transmission providers must evaluate in Long-Term Regional Transmission Planning. The Commission explained that this minimum number of Long-Term Scenarios would help to ensure that transmission providers conduct Long-Term Regional Transmission Planning that identifies more efficient or cost-effective regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand. The Commission explained that to satisfy this requirement, transmission providers could develop a base case and three alternatives, or a low-, medium-, and high-level assumption for the factors that transmission providers (and their stakeholders) believe to be important to conduct Long-Term Regional Transmission Planning to more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand, along with a scenario that accounts for a high-impact, low-frequency event (as discussed below).[1167]

539. Consistent with the Order No. 890 transparency transmission planning principle,[1168] the Commission proposed to require transmission providers in each transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs they use to create each Long-Term Scenario. The Commission explained that this transparency requirement will allow stakeholders to understand how each scenario differs.

540. Similarly, consistent with the coordination transmission planning principle established in Order No. 890,[1169] the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input into the identification of which Long-Term Scenarios are developed. The Commission proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. Furthermore, the Commission proposed to require transmission providers to explain on compliance how their process will identify a plausible and diverse set of Long-Term Scenarios.[1170]

b. Comments

541. Many commenters support requiring transmission providers in each transmission planning region to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[1171] GridLab and R Street state that this proposed requirement appropriately balances the need to address uncertainty and risk factors associated with long-term transmission planning while limiting the complexity of the transmission planning process.[1172] PJM says that employing multiple scenarios will ensure that transmission providers' plans reflect changing needs while avoiding the risk of over-building.[1173] SEIA states that requiring four distinct Long-Term Scenarios will allow transmission providers to reflect the uncertainty inherent in long-term planning.[1174] AEE states that the Commission should establish a minimum number of scenarios as a baseline for compliance with any final order.[1175] New York TOs support requiring the use of multiple scenarios for Long-Term Regional Transmission Planning, noting that NYISO already incorporates multiple scenarios into its transmission planning processes.[1176] Nevada Commission notes that information from four scenarios could provide inputs into Nevada's integrated regional planning process and identify both local and regional needs.[1177]

542. Policy Integrity argues that the Commission should require more than four Long-Term Scenarios.[1178] Policy Integrity identifies planning efforts that have used more than four scenarios to illustrate that best practice counsels against reducing the number of required Long-Term Scenarios.[1179] Northwest and Intermountain state that, depending upon the size and characteristics of the transmission planning region, additional scenarios may be necessary to identify the transmission facilities that are most likely to ensure just and

to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarified that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in this final rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.

[1166] NOPR, 179 FERC ¶ 61,028 at PP 121–126.

[1167] *Id.* P 122.

[1168] The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

[1169] The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at PP 451–454.

[1170] NOPR, 179 FERC ¶ 61,028 at P 123.

[1171] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8, 18; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18–19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4–5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8–9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 6–7; US Chamber of Commerce Initial Comments at 7; US DOE Initial Comments at 14; Vermont Electric and Vermont Transco Initial Comments at 2.

[1172] GridLab Initial Comments at 12; R Street Initial Comments at 6.

[1173] PJM Initial Comments at 74.

[1174] SEIA Initial Comments at 11.

[1175] AEE Reply Comments at 18.

[1176] New York TOs Initial Comments at 2.

[1177] Nevada Commission Initial Comments at 8–9.

[1178] Policy Integrity Initial Comments at 14–16.

[1179] *Id.* at 15 (citing US DOE et al., Presentation on National Transmission Planning Study at the Modeling Subcommittee Meeting, at slide 21 (June 7, 2022), *https://perma.cc/MEJ5-9JE6* (study will use approximately 100 scenarios); ERCOT, Report On Existing and Potential Electric System Constrains and Needs 10 (Dec. 2020), *https://perma.cc/JGS4-9VH7* (ERCOT has previously used five scenarios); Mohamed Labib Awad et al., *Using Market Simulations for Economic Assessment of Transmission Upgrades: Application of the California ISO Approach, in Restructured Electric Power Systems: Analysis Of Electricity Markets With Equilibrium Models* 241, 255 (Xiao-Ping Zhang ed. 2010) (economists evaluating CAISO have used seventeen scenarios)).

reasonable rates.[1180] LADWP states that while developing more than four scenarios will likely be prudent in some instances such as special studies, four scenarios should be adequate for most Long-Term Regional Transmission Planning given the 20-year planning horizon and uncertainties.[1181]

543. Some commenters stress the importance of considering multiple Long-Term Scenarios and the uncertainty associated with future conditions.[1182] ACORE suggests that uncertainties in data can be addressed with multiple Long-Term Scenarios that are continuously revised instead of granting flexibility or encouraging discounting of certain factors.[1183] ENGIE states that a single base-case scenario is not effective at capturing trends in the resource mix and demand.[1184] New York Commission and NYSERDA state that Long-Term Scenarios should reflect a range of plausible long-term futures that are relevant to the state (or transmission planning region) and should account for the uncertainty associated with looking out over longer time horizons.[1185] On the other hand, R Street posits that whether scenario planning sufficiently captures information on the resource mix and demand depends more on the quality of inputs and scenario construction elements than the total number of scenarios.[1186]

544. Some commenters generally support requiring Long-Term Scenarios[1187] including scenarios examining the effects of high energy demand,[1188] and penetration of renewable resources.[1189]

545. Other commenters do not oppose this requirement.[1190]

546. Some commenters support requiring transmission providers to establish Long-Term Scenarios, but would modify the NOPR proposal to require a lower minimum number. AEP, Entergy, NRECA, Pine Gate, and Western PIOs support requiring at least three Long-Term Scenarios.[1191] CAISO argues that the Commission should not require transmission providers to develop a minimum of four Long-Term Scenarios because there is no evidence, rationale, or justification for why four is the appropriate number of scenarios to develop.[1192] Instead, CAISO asserts that the Commission should grant transmission planners the flexibility to determine the minimum number of Long-Term Scenarios that are appropriate given the specific circumstances in their region and planning cycle. However, CAISO states that if Commission were to adopt a minimum number of Long-Term Scenarios, three Long-Term Scenarios is appropriate because it allows for a base case scenario and two sensitivity scenarios.[1193] Entergy and NRECA claim that three Long-Term Scenarios would better balance the burden with the benefit of developing an additional scenario.[1194] Pine Gate recommends that, instead of requiring a fourth scenario, the Commission should permit transmission providers in each transmission planning region to develop and use no less than three Long-Term Scenarios, and then to conduct either a fourth scenario or a sensitivity analysis on the most likely Long-Term Scenario to ''account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low frequency events'' as proposed in the NOPR.[1195]

547. National Grid argues that there is an inherent trade-off between the number of Long-Term Scenarios, the quality of the data underpinning the assessment, and the frequency of reassessments. National Grid concludes that a transmission provider should not be required to plan for a scenario that is impossible or not supported by its stakeholders solely to meet the requirement that four distinct Long-Term Scenarios be developed and studied.[1196] Xcel supports the use of scenarios but states that the proposed requirement to use at least four Long-Term Scenarios is too prescriptive.[1197] Relatedly, LADWP states that developing more than four Long-Term Scenarios may be prudent in some instances but that it would be inefficient and a waste of resources to require all transmission providers in each transmission planning region to do so.[1198]

548. Some commenters broadly oppose the NOPR proposal to require transmission providers in each transmission planning region to develop at least a minimum number or specific number of Long-Term Scenarios.[1199] California Commission argues that the NOPR's approach would interfere with regional transmission planning processes, such as CAISO's, that are closely coordinated with state resource planning and load forecasting and already effectively identify transmission necessary to accommodate changes in the resource mix and demand.[1200] Duke argues that requiring a minimum number of Long-Term Scenarios, while also requiring one capture high-impact, low-frequency events, places greater importance on developing scenarios purely to satisfy the requirement than on gaining consensus about what scenarios are in fact plausible or most likely.[1201] MISO states that a prescriptive number of Long-Term Scenarios with specific factors included may introduce a level of granularity and complexity into Long-Term Regional Transmission Planning that impedes progress.[1202]

549. Some commenters request that the Commission provide transmission providers in each transmission planning region with the flexibility to determine how many Long-Term Scenarios to develop.[1203] US DOE supports a

[1180] Northwest and Intermountain Initial Comments at 12.

[1181] LADWP Initial Comments at 4.

[1182] ACORE Initial Comments at 10; ENGIE Initial Comments at 3–4; New York Commission and NYSERDA Initial Comments at 8; R Street Initial Comments at 6.

[1183] ACORE Initial Comments at 10.

[1184] ENGIE Initial Comments at 4.

[1185] New York Commission and NYSERDA Initial Comments at 8.

[1186] R Street Initial Comments at 6.

[1187] Breakthrough Energy Supplemental Comments at 1; Clean Energy Associations Initial Comments at 11–12; Cross Sector Representatives Supplemental Comments at 1; PJM Initial Comments at 6, 71–72; RMI Supplemental Comments at 2; US Climate Alliance Initial Comments at 2; Western PIOs Initial Comments at 29.

[1188] ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

[1189] ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

[1190] Clean Energy Buyers Initial Comments at 17; Dominion Initial Comments at 25; Pine Gate Initial Comments at 26; Utah Division of Public Utilities Initial Comments at 5.

[1191] AEP Initial Comments at 5, 8, 12; Entergy Initial Comments at 13; NRECA Initial Comments 35; Pine Gate Initial Comments at 26–27; Western PIOs Initial Comments at 33.

[1192] CAISO Initial Comments at 23–24.

[1193] *Id.* at 25–26.

[1194] Entergy Initial Comments at 13; NRECA Initial Comments 35.

[1195] Pine Gate Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

[1196] National Grid Initial Comments at 14–15.

[1197] Xcel Initial Comments at 10.

[1198] LADWP Initial Comments at 4.

[1199] California Commission Initial Comments at 21–24; Duke Initial Comments at 15; Indicated PJM TOs Initial Comments at 9–10; ISO–NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30; OMS Initial Comments at 5; PG&E Initial Comments at 6–7; SPP Initial Comments at 9–10; State Agencies Initial Comments at 14.

[1200] California Commission Initial Comments at 23.

[1201] Duke Initial Comments at 15.

[1202] MISO Initial Comments at 20.

[1203] Ameren Initial Comments at 13–14; Avangrid Initial Comments at 9–10; CAISO Initial Comments at 25; California Energy Commission Initial Comments at 2; Clean Energy Associations Initial Comments at 11–12; Dominion Initial Comments at 25; Entergy Initial Comments at 13; MISO Initial

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requirement to identify four scenarios as a reasonable lower bound, and supports the analysis of additional scenarios, including sensitivities, but asserts that the development of Long-Term Scenarios should not be prescriptive but, rather, the Commission should provide guidelines and give transmission planning regions flexibility to work within those guidelines to capture reasonable sets of scenarios.[1204]

550. Some commenters propose that, if the Commission does not require a minimum number of Long-Term Scenarios, the Commission should instead require that transmission providers in each transmission planning region demonstrate, on compliance, why their proposed number of Long-Term Scenarios is appropriate.[1205] Duke asserts that the Commission should direct transmission providers to offer on compliance a process for Long-Term Scenario development that will capture enough sufficiently plausible scenarios with distinct sets of assumptions to adequately capture a consensus view of the most likely future state(s) to occur.[1206]

551. Other commenters call for the Commission to permit discretion on how transmission providers determine the number of Long-Term Scenarios to use.[1207] ISO–NE and ISO/RTO Council argue that the number of Long-Term Scenarios is an implementation detail that each transmission planning region should decide.[1208] NYISO states that the final order should permit each transmission planning region to conduct Long-Term Regional Transmission Planning using multiple Long-Term Scenarios that account for varying levels of achievement of local laws and regulations.[1209]

552. MISO opposes requiring transmission providers to evaluate a specific number of Long-Term Scenarios and proposes, instead, that the Commission require that future scenarios be developed and implemented for purposes of long-term regional transmission planning, leaving each transmission planning region to determine what and how many scenarios are appropriate. According to MISO, this approach would ensure consistency across the transmission planning regions in what is required while allowing for any needed variation within each region.[1210] Additionally, MISO notes that it developed the futures that it uses in its Long-Range Transmission Plan through extensive stakeholder processes and that these futures reflect the specific realities of its member utilities. MISO contends that allowing transmission providers to develop the number of Long-Term Scenarios they need, and at intervals appropriate for them, encourages stakeholder buy-in and more efficient allocation of planning resources.[1211]

553. California Municipal Utilities disagree with comments that urge prescriptive uniformity, arguing that uniformity involves high costs and lacks consumer protection measures against speculative transmission projects.[1212] For example, California Municipal Utilities argue against the proposal from Western PIOs for the development of three common scenarios to be synchronized across the Western Interconnection because this proposal amounts to central resource planning, which is not consistent with the existing process in which state and local choices drive the planning process.[1213]

554. Louisiana Commission states that the Commission's proposal is overly prescriptive and that the Commission should provide for a more flexible approach that allows transmission providers, retail regulators, and other stakeholders to develop scenarios with appropriate, realistic, and reasonable assumptions. Louisiana Commission states that Long-Term Scenarios should be based on reasonable ranges of assumptions for load, and generation type and location. Louisiana Commission argues that the number of scenarios required is far less important than the quality of the data and assumptions used to develop them.[1214] MISO TOs agree that the NOPR proposal is overly prescriptive, stating that the Commission should not create unnecessary obstacles, but rather create a rule broad enough to incorporate existing processes.[1215]

555. Some commenters emphasize the need for an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to provide timely and meaningful input into which Long-Term Scenarios are developed.[1216] For example, California Commission, NRECA, Concerned Scientists, and US Climate Alliance support the NOPR proposal to require transmission providers to disclose—subject to any applicable confidentiality protections—information and data inputs that they use to create each Long-Term Scenario.[1217] ELCON states that the Commission should require each transmission provider to post all methodologies and inputs used in determining Long-Term Scenarios and factors to its OASIS.[1218] NRG claims that the NOPR proposes a central determination of particular actions based on collectively determined assumptions, which gives up a major advantage of competition—the requirement that market participants take an individual view based on available information of the future viability of any investment they might make.[1219]

556. NESCOE argues that states must play a central role in Long-Term Regional Transmission Planning. Specifically, NESCOE agrees with ISO–NE, which calls for the Commission to explicitly authorize states to have a central decision-making role at all aspects of Long-Term Regional Transmission Planning, including ''scenario analysis development,'' to ensure necessary additional investment for a reliable, clean energy future.[1220] Similarly, Nebraska Commission adds that state regulatory commissions should have a significant role in defining Long-Term Scenarios.[1221]

557. AEE requests that the Commission clarify the role of states in providing input to the development of Long-Term Scenarios.[1222]

558. GridLab states that the Commission should be prepared to act

Comments at 16, 20; MISO TOs Initial Comments at 16–17; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 5; PG&E Initial Comments at 7; PJM Initial Comments at 72; SPP Initial Comments at 9; US DOE Initial Comments at 14; Xcel Initial Comments at 10.

[1204] US DOE Initial Comments at 14.

[1205] CAISO Initial Comments at 25; Duke Initial Comments at 15; Eversource Initial Comments at 17–18; NESCOE Initial Comments at 30–31.

[1206] Duke Initial Comments at 15.

[1207] Indicated PJM TOs Initial Comments at 9–10; ISO–NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30–31; OMS Initial Comments at 5.

[1208] ISO–NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9.

[1209] NYISO Initial Comments at 23.

[1210] MISO Initial Comments at 16, 20.

[1211] MISO Reply Comments at 9–10.

[1212] California Municipal Utilities Reply Comments at 5.

[1213] *Id.* (citing Western PIOs Initial Comments at 32–33).

[1214] Louisiana Commission Reply Comments at 6–7.

[1215] MISO TOs Reply Comments at 13.

[1216] California Commission Initial Comments at 25; Clean Energy Associations Initial Comments at 12; DC and MD Offices of People's Counsel Initial Comments at 14; ELCON Initial Comments at 12; NRECA Initial Comments at 35; Pacific Northwest State Agencies at 14–15; US Climate Alliance Initial Comments at 2.

[1217] California Commission Initial Comments at 25; NRECA Initial Comments at 35; Concerned Scientists Reply Comments at 15–16; US Climate Alliance Initial Comments at 2.

[1218] ELCON Initial Comments at 12.

[1219] NRG Initial Comments at 8.

[1220] NESCOE Reply Comments at 2 (citing ISO–NE Initial Comments at 2–4).

[1221] Nebraska Commission Initial Comments at 5–6.

[1222] AEE Initial Comments at 19.

as the arbiter of stakeholder concerns about Long-Term Scenario design, similar to the role that state public utility commissions play in the integrated resource planning process, and that this may require new staff, resources, and the development of new expertise at the Commission.[1223]

c. Commission Determination

559. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. In implementing this requirement, transmission providers must develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section above. We find that requiring transmission providers to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning strikes the appropriate balance between establishing a sufficient number of Long-Term Scenarios and the associated burden of developing and using Long-Term Scenarios in Long-Term Regional Transmission Planning. We also find that requiring transmission providers to develop at least three distinct Long-Term Scenarios instead of four, as proposed in the NOPR, is more consistent with the manner in which some transmission providers currently employ scenarios in their existing regional transmission planning process.[1224] We also reiterate, as stated in the NOPR, that if transmission providers produce a base-case Long-Term Scenario in Long-Term Regional Transmission Planning, that base case should be consistent with what the transmission provider determines is the most likely scenario to occur.[1225]

560. In addition, we adopt the NOPR proposal to require, consistent with Order No. 890's transparency transmission planning principle, transmission providers in each transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs that they use to create each Long-Term Scenario.[1226] We also adopt the NOPR proposal to require transmission providers in each transmission planning region, consistent with Order No. 890's coordination transmission planning principle, to provide stakeholders an opportunity to provide timely and meaningful input into how Long-Term Scenarios are developed.[1227] Consistent with Order No. 890 and Order No. 1000's coordination transmission planning principle, we require transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders. Furthermore, we adopt the NOPR proposal to require transmission providers to revise the regional transmission planning process in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. We conclude that these requirements will help ensure that transmission providers will have the necessary information to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. Furthermore, by requiring transmission providers to afford stakeholders a meaningful opportunity to propose future outcomes that are probable, we believe that this requirement helps to ensure that Long-Term Transmission Needs are being addressed in a more efficient or cost-effective manner.[1228]

561. We also note the important role of states in developing Long-Term Scenarios. As the Commission stated in Order No. 890 and Order No. 1000, and we reiterate here, our expectation is that ''all transmission providers will respect states' concerns'' when engaging in the regional transmission planning process.[1229] We strongly encourage states to participate actively in the development of Long-Term Scenarios, as well as in all other aspects of Long-Term Regional Transmission Planning. In response to NESCOE's and AEE's concerns about the role of state regulators in the development of Long-Term Scenarios and their use in Long-Term Regional Transmission Planning,[1230] we find that, consistent with Order No. 890,[1231] transmission planning must be coordinated with interested stakeholders, including relevant state regulators that wish to participate in the Long-Term Regional Transmission Planning process. As reflected throughout this final order, we recognize that states have a particularly important role to play in the development of Long-Term Regional Transmission Facilities and encourage transmission providers to work with states in a way that reflects that role in addition to complying with the relevant requirements established herein.

562. In response to commenters that argue that the Commission should require four or more Long-Term Scenarios,[1232] we affirm that nothing in this final order precludes or prevents transmission providers from proposing

[1223] GridLab Initial Comments at 11–12.

[1224] *See, e.g.,* CAISO Initial Comments at 26 (explaining that ''CAISO typically has utilized three scenarios in its public policy planning process, a base case scenario and two sensitivity scenarios''); Entergy Initial Comments at 13–14 (explaining that MISO currently uses three scenarios in its transmission planning process and arguing that the use of three scenarios enables ''transmission providers to 'bookend' plausible outcomes to plan no-regrets additions to meet the grid, and then develop a scenario between those two to better inform the decision making''); NRECA Initial Comments at 35 n.100 (highlighting that MISO uses three scenarios in its transmission planning process).

[1225] NOPR, 179 FERC ¶ 61,028 at P 123.

[1226] The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

[1227] The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at P 454.

[1228] Order No. 1000, 136 FERC ¶ 61,051 at P 150.

[1229] *Id.* P 212; Order No. 890, 118 FERC ¶ 61,119 at P 574.

[1230] AEE Initial Comments at 8; NESCOE Reply Comments at 2 (citing ISO–NE Initial Comments at 2–4).

[1231] Order No. 890, 118 FERC ¶ 61,119 at P 574.

[1232] ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18–19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4–5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8–9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 7; US Chamber of Commerce Initial Comments at 7; US DOE Initial Comments at 14–15; Vermont Electric and Vermont Transco Initial Comments at 2.

to use more than three Long-Term Scenarios in Long-Term Regional Transmission Planning. To the extent that transmission providers, in consultation with stakeholders, conclude that using more than three Long-Term Scenarios is appropriate for Long-Term Regional Transmission Planning in their transmission planning region, those transmission providers may propose to use more than three Long-Term Scenarios in their compliance filings.

563. In response to California Commission's comments about the interaction between the development of Long-Term Scenarios and existing regional transmission planning processes,[1233] we believe the final order, as modified from the NOPR proposal, addresses this concern and provides transmission providers with sufficient flexibility to tailor the development of Long-Term Scenarios to their transmission planning regions' specific needs or existing practices, as discussed elsewhere in this final order.[1234]

5. Types of Long-Term Scenarios

a. NOPR Proposal

564. In the NOPR, the Commission proposed to require that each Long-Term Scenario incorporate, at a minimum, the categories of factors listed in the requirement above. As discussed in the Factors section of the NOPR,[1235] the Commission proposed that each Long-Term Scenario must be consistent with Federal, state, and local laws and regulations that affect the future resource mix; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans. However, the Commission explained that each Long-Term Scenario may vary according to assumptions about the remaining categories of factors described in the NOPR, as well as with respect to other characteristics of the future electric power system. The Commission explained that it neither proposed to require the development of a specific Long-Term Scenario or specific set of Long-Term Scenarios, nor did it propose to require that transmission providers identify the relative likelihood of different Long-Term Scenarios except where transmission providers develop a base case scenario, as described more fully below.[1236]

565. The Commission proposed to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.[1237] The Commission explained that the set of at least four Long-Term Scenarios must be: (1) plausible, that is they must reasonably capture probable future outcomes, and (2) diverse in the sense that transmission providers must be able to distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario. The Commission proposed to require that if the transmission providers in a transmission planning region use a base case scenario, that scenario should be consistent with the scenario that the transmission providers determine to be the most likely scenario to occur.

b. Comments

566. Some commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.[1238] For example, GridLab agrees that the Commission should require that transmission providers demonstrate that their Long-Term Scenarios capture a reasonable range of possible futures. GridLab argues that scenarios that are too conservative will lead to similar load-resource and transmission portfolio scenarios, which limits the value of scenario planning in managing uncertainty and risk.[1239] Illinois Commission argues that the NOPR's proposed requirement for diverse and plausible scenarios is important, and that Long-Term Scenarios must consider a wide array of conditions.[1240]

567. Some commenters discuss the need for certain types of Long-Term Scenarios.[1241] Certain TDUs and PIOs argue that, although Long-Term Scenarios should include anticipated levels of generation, they should also include ''book end'' scenarios of high- and low-load growth.[1242] Clean Energy Associations argue that, because the Inflation Reduction Act provides for significant funding for electrification, at least some scenarios should evaluate transmission needs under higher-than-anticipated load growth.[1243]

568. PJM describes four scenarios that it might use: (1) a low uncertainty scenario with known inputs, such as legislative and regulatory laws and announced deactivations and load forecasts; (2) a medium uncertainty scenario that includes state and local goals and economic retirement analysis; (3) a higher uncertainty scenario that adds more speculative and aspirational goals; and (4) a high-impact-low-frequency resilience evaluation scenario that includes low-probability, high-impact events. PJM states that the scenarios should be: (1) based on a clearly defined, robust set of factor development criteria grounded in customer needs; (2) capable of adapting to an evolving set of future system conditions; and (3) crafted to produce the appropriate level of transmission.[1244]

569. Western PIOs state that one scenario should be based on existing policy and assumptions about generation retirements and electrification that are likely to occur. Western PIOs state that a second scenario would build on that base case scenario by assuming Public Policy Requirements and utility and corporate goals are met or exceeded, as well as high levels of electrification and generation retirements. Western PIOs state that a third scenario should address high-impact, low-frequency extreme weather events. Western PIOs state that the fourth scenario could be reserved for a scenario unique to each of the non-RTO/ISO transmission planning regions.[1245]

570. ACORE argues that uncertainties in data do not require granting

[1233] California Commission Initial Comments at 23.

[1234] *See supra* Categories of Factors, Requirement to Incorporate Categories of Factors section; Categories of Factors, Stakeholder Process and Transparency section.

[1235] NOPR, 179 FERC ¶ 61,028 at PP 104–112.

[1236] *Id.* P 121.

[1237] The Commission noted that different assumptions about the factors and data inputs used to develop Long-Term Scenarios and other characteristics of the future electric power system determine whether the set of Long-Term Scenarios are plausible and diverse.

[1238] APPA Initial Comments at 29; Clean Energy Buyers Initial Comments at 17; DC and MD Offices of People's Counsel Initial Comments at 13; GridLab Initial Comments at 11 & n.12; Illinois Commission Initial Comments at 7; Mississippi Commission Reply Comments at 9; NARUC Initial Comments at 10; NESCOE Initial Comments at 32; New York Commission and NYSERDA Initial Comments at 8; SPP Market Monitor Initial Comments at 7.

[1239] GridLab Initial Comments at 11.

[1240] Illinois Commission Initial Comments at 7.

[1241] ACORE Initial Comments at 10–11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18; Clean Energy Associations Initial Comments at 10–11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 18–19; Georgia Commission Initial Comments at 4–5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22–23; PJM Initial Comments at 73–74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5–6; Western PIOs Initial Comments at 33.

[1242] Certain TDUs Initial Comments at 18; PIOs Initial Comments at 22–23.

[1243] Clean Energy Associations Initial Comments at 11 (citing Inflation Reduction Act, Public Law 117–169 (2022)).

[1244] PJM Initial Comments at 73–74.

[1245] Western PIOs Initial Comments at 33.

flexibility or encouraging discounting, but instead can be addressed with multiple scenarios that are continuously revised as recommended in the NOPR. For example, one Long-Term Scenario can include a discounted set of goals, while another can add contingency factors for when demand exceeds those goals; and a range of scenarios could be incorporated for the extent of electrification of buildings and transportation. ACORE states that scenario analysis should incorporate a probabilistic-based range of future weather and extreme events which, ACORE asserts, will support the analyses of the benefits of mitigation of those extreme events and system contingencies and mitigation of weather and load uncertainty.[1246]

571. AEE recommends that the Commission require Long-Term Scenarios that consider anticipated distributed energy resource deployments.[1247] Evergreen Action urges the Commission to require that at least one Long-Term Scenario contemplate a 100% clean-energy grid by 2035, to reflect the Biden Administration's target of 100% carbon-free electricity by 2035.[1248] Similarly, NextEra argues that the Commission should require that one of the Long-Term Scenarios be based on an economy-wide, net-zero emissions scenario or at least a Federal net-zero emissions mandate limited to the power sector.[1249] In contrast, Utah Division of Public Utilities states that one of the Long-Term Scenarios should consider little or no state renewable energy or decarbonization goals or requirements to assist in determining transmission costs for states that have less onerous goals.[1250]

572. APPA requests that one of the Long-Term Scenarios represent a base case of business as usual.[1251] Eversource supports the NOPR proposal to use the ''most likely scenario to occur'' as the base case for analysis of Long-Term Scenarios.[1252] Georgia Commission argues that a base case scenario should reflect the expected long-term mix of generating capacity, with additional scenarios reflecting alternative carbon emission constraints, fuel prices, and growth in distributed energy resources.[1253] US Climate Alliance states that business-as-usual cases should be consistent with state and Federal policy and used in addition to alternative scenarios that demonstrate a range of factors influencing the changing grid.[1254]

573. However, PIOs state that the Commission should not use the phrase ''business as usual'' as it is misleading in a rapidly changing electric industry.[1255] US DOE argues against identifying the likelihood of any one Long-Term Scenario, including a base case scenario, because identifying a single such scenario as most likely is challenging and discourages the analysis of more scenarios and sensitivities, undermining the value of scenario analysis. Instead, US DOE argues that transmission facilities that provide high value in multiple scenarios should be identified as more likely to provide value to the future transmission system, because expansion options that provide high value in many future scenarios are flexible, and that flexibility to accommodate multiple future scenarios is more important than trying to characterize the likelihood of any one scenario.[1256]

574. Senator Schumer supports requiring a high variable energy resource penetration scenario.[1257]

c. Commission Determination

575. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of at least three Long-Term Scenarios. Specifically, we find that the set of at least three Long-Term Scenarios must be: (1) plausible, meaning that each scenario must itself be reasonably probable, and collectively that the set of plausible scenarios must reasonably capture probable future outcomes, and (2) diverse, in the sense that transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each Long-Term Scenario. We find that requiring Long-Term Scenarios to be both plausible and diverse prevents the development of Long-Term Scenarios that may otherwise be too conservative, speculative, or similar for transmission providers to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. Absent a requirement that Long-Term Scenarios be both plausible and diverse, transmission providers could develop Long-Term Scenarios in a manner that undercuts one of the primary benefits of using scenario-based planning practices, which is to help ensure that transmission providers can account for the uncertainty about future conditions when conducting Long-Term Regional Transmission Planning.

576. Moreover, we also require that each *individual* Long-Term Scenario be plausible (*i.e.,* individually the scenario must be reasonably probable) because, absent such a requirement, we are concerned that the set of Long-Term Scenarios may include a Long-Term Scenario that rests on assumptions about the factors and data inputs that do not reasonably capture possible future outcomes. Additionally, we also clarify the term ''diverse'' to mean that the *set* of Long-Term Scenarios must represent a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.

577. We disagree with commenters that argue that the Commission should modify the NOPR proposal and prescribe specific types of Long-Term Scenarios for transmission providers to use in Long-Term Regional Transmission Planning.[1258] We are not persuaded that we should require transmission providers to develop either a specific Long-Term Scenario or a specific set of Long-Term Scenarios because we believe that transmission providers, with an opportunity for timely and meaningful input from stakeholders, are in the best position to determine which plausible Long-Term Scenarios are applicable to their transmission planning region. Further, we do not find it necessary to require transmission providers to develop low-, medium-, and high-level assumptions for the factors that transmission providers believe to be important except where transmission providers develop a base case scenario, as discussed above.[1259]

[1246] ACORE Initial Comments at 10–11.

[1247] AEE Initial Comments at 8.

[1248] Evergreen Action Initial Comments at 3.

[1249] NextEra Initial Comments at 65.

[1250] Utah Division of Public Utilities Initial Comments at 5–6.

[1251] APPA Initial Comments at 29.

[1252] Eversource Initial Comments at 19.

[1253] Georgia Commission Initial Comments at 4–5.

[1254] US Climate Alliance Initial Comments at 2.

[1255] PIOs Initial Comments at 22.

[1256] US DOE Initial Comments at 15.

[1257] Senator Schumer Supplemental Comments at 2.

[1258] ACORE Initial Comments at 10–11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18, 22; Clean Energy Associations Initial Comments at 11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 19; Georgia Commission Initial Comments at 4–5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22–23; PJM Initial Comments at 73–74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5–6; Western PIOs Initial Comments at 33.

[1259] *See supra* Types of Long-Term Scenarios section.

6. Sensitivities for High-Impact, Low-Frequency Events

a. NOPR Proposal

578. In the NOPR, the Commission proposed to require that at least one of the four distinct Long-Term Scenarios that transmission providers in each transmission planning region use in Long-Term Regional Transmission Planning account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. The Commission proposed to allow transmission providers the flexibility to determine which high-impact, low-frequency event should be modeled in this Long-Term Scenario as part of Long-Term Regional Transmission Planning based on the Commission's understanding that each transmission planning region may see a need to evaluate a different type of high-impact, low-frequency event. The Commission stated that high-impact, low-frequency events may include extreme weather events or events associated with potential cyber-attacks. The Commission explained that this Long-Term Scenario accounting for a high-impact, low-frequency event can be developed, for example, by assuming greater-than-expected electricity demand and greater-than-expected generation or transmission outages. The Commission proposed that the use of either probabilistic transmission planning [1260] or stochastic techniques would be sufficient to satisfy this requirement, but it did not propose to require either approach at this time.[1261]

579. The Commission noted that transmission providers can develop sensitivities for every Long-Term Scenario to assess how outcomes modeled in Long-Term Scenarios may depend on an assumption about electric power system model inputs that does not vary across scenarios (*e.g.,* higher natural gas prices). The Commission explained that such sensitivities can provide valuable information about the need for and benefits of potential transmission facilities, but also noted that they can be burdensome to develop if applied to every scenario.[1262]

b. Comments

580. Some commenters support the NOPR proposal to require one Long-Term Scenario to account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events as part of Long-Term Regional Transmission Planning.[1263] Ameren states that the inclusion of such events in Long-Term Regional Transmission Planning would provide additional information for transmission providers, stakeholders, state regulators, and others to consider when determining the need for regional transmission facilities.[1264] According to Arizona Commission, including such a scenario, and giving the transmission provider the discretion to determine what this should be for its region, may provide the added benefit of allowing state involvement in identifying the appropriate ''high-impact'' event to be analyzed. Arizona Commission additionally asserts that the Commission should require transmission providers to develop sensitivities for each Long-Term Scenario to better understand the range of benefits under each scenario.[1265]

581. Eversource supports the NOPR proposal given the increasing threat of extreme weather events and potential cyber-attacks.[1266] Similarly, Illinois Commission states that the inclusion of high-impact, low-frequency events in the transmission planning process is reasonable and should include cyber-security attacks and extreme weather events to strengthen the system's resilience.[1267] New England for Offshore Wind argues that it is prudent for the Commission to require transmission providers to develop at least one high-impact, low-frequency scenario due to the increased likelihood of extreme weather events due to climate change.[1268] SoCal Edison states that incorporating probabilistic assumptions about extreme weather in Long-Term Scenarios would be a reasonable, proactive approach to mitigate the impacts of extreme weather when it occurs.[1269]

582. Likewise, Cypress Creek, City of New Orleans Council, DC and MD Offices of People's Counsel, and PIOs support the inclusion of extreme weather events in Long-Term Scenarios.[1270] Business Council for Sustainable Energy contends that Long-Term Scenarios must account for the increase in significant climate events, acknowledging that the most salient events to assess may vary regionally.[1271] US DOE asserts that regional transmission planning should consider the effects of extreme events, including extreme weather events, on the availability and reliability of the transmission system.[1272] WE ACT comments that requiring transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events brought on by the climate crisis.[1273]

583. Other commenters express more general support for the study of high-impact, low-frequency events in Long-Term Regional Transmission Planning.[1274] Clean Energy Associations emphasize that no scenario or sensitivity should assume that historical operating conditions will persist given the unpredictable and increasing impact of climate change.[1275] Grid United states that high-impact, low-frequency scenarios should not be considered ''black swan'' events since they occur on a regular, but low-frequency, basis. Moreover, Grid United asks that the Commission define or provide examples of high-impact, low-frequency events that transmission providers could incorporate into Long-Term Scenarios to

[1260] NOPR, 179 FERC ¶ 61,028 at P 124. The Commission stated that it considers probabilistic transmission planning approaches to include any transmission planning approach that uses a probability distribution to assign probabilities to one or more inputs to the transmission model. The Commission stated that these inputs can include shorter-term operational inputs (like wind generation or generation outages). The Commission described stochastic techniques as including adaptive transmission planning techniques that identify transmission facilities that optimize transmission net-benefits over a time horizon under market and regulatory uncertainty about the future. *Id.* P 124 n.228.

[1261] *Id.* P 124.

[1262] *Id.* P 125.

[1263] Ameren Initial Comments at 13; Arizona Commission Initial Comments at 6; California Commission Initial Comments at 24; Evergreen Action Initial Comments at 4; Eversource Initial Comments at 18; Grid United Initial Comments at 4; New England for Offshore Wind Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 14; US DOE Initial Comments at 15.

[1264] Ameren Initial Comments at 13–14.

[1265] Arizona Commission Initial Comments at 6–7.

[1266] Eversource Initial Comments at 18.

[1267] Illinois Commission Initial Comments at 6.

[1268] New England for Offshore Wind Initial Comments at 2.

[1269] SoCal Edison Initial Comments at 12.

[1270] City of New Orleans Council Initial Comments at 8; Cypress Creek Reply Comments at 5–6; DC and MD Offices of People's Counsel Reply Comments at 6; PIOs Reply Comments at 10; *see also* RMI Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2–3.

[1271] Business Council for Sustainable Energy Initial Comments at 4.

[1272] US DOE Initial Comments at 5.

[1273] WE ACT Initial Comments at 2.

[1274] *See* Business Council for Sustainable Energy Initial Comments at 4; Clean Energy Associations Initial Comments at 12; Evergreen Action Initial Comments at 3–4; Grid United Initial Comments at 4–5; NARUC Initial Comments at 11–12; NASUCA Initial Comments at 4–5; NESCOE Initial Comments at 32–33; NRECA Initial Comments at 35–36; Pattern Energy Initial Comments at 25; SoCal Edison Initial Comments at 12.

[1275] Clean Energy Associations Initial Comments at 12.

provide clarity and consistency across transmission planning regions.[1276]

584. NARUC does not oppose the requirement that one of the Long-Term Scenarios account for high-impact, low-frequency events but notes that states' input is important when developing such scenarios.[1277] Pattern Energy states that, with respect to low-probability, high-risk event scenarios, the Commission should: (1) require the North American Electric Reliability Corporation and the Regional Entities to develop the scope of low-probability, high-risk events for each region of the country and then (2) require transmission providers to model at least one of the events in a rotation of the three-year review of the 20-year plans to identify vulnerabilities that can be addressed through transmission solutions that increase resilience.[1278] Vermont Electric and Vermont Transco request clarity on what scenarios the Commission would consider sufficiently high-impact to be analyzed but not so high-impact as to be unable to be mitigated by effective Long-Term Regional Transmission Planning.[1279]

585. Some commenters support the Commission's proposal to permit transmission providers to model high-impact, low-frequency events via probabilistic or stochastic methods.[1280] PJM states that it will sometimes use probabilistically-derived parameters and sometimes use deterministically-derived parameters in its Long-Term Scenarios, depending on which is more appropriate.[1281] Policy Integrity asserts that the Commission should ensure the use of modeling techniques that address uncertainty, such as stochastic programming and robust optimization models.[1282] Policy Integrity argues that modeling that fails to consider uncertainties that arise from various factors could reduce the cost-efficacy and efficiency of results and, ultimately, result in unjust and unreasonable rates.[1283] Policy Integrity cites the European Network of Transmission System Operators' consideration of the interactions between gas and electric systems as an example of best practices for choosing scenarios.[1284]

586. Some commenters provided views on the Commission's proposal to require transmission providers to develop sensitivities for each Long-Term Scenario.[1285] Business Council for Sustainable Energy states that it is important that scenario planning cover a range of sensitivities, and that the long-term needs of the transmission system as well as long-term policy goals should be incorporated.[1286] NERC states that studies could more adequately study various sensitivities and extreme conditions (*e.g.,* extreme weather) to ensure a reliable, resilient, and secure bulk power system on a longer time horizon, which could, in turn, help inform transmission expansion plans particularly related to the changing resource mix.[1287]

587. GridLab recommends that the Commission provide a high-level requirement and guidance on what kinds of factors are more effectively considered in scenario versus sensitivity analysis and how sensitivity analysis might be used in tandem with scenario analysis.[1288] Policy Integrity states that, instead of mandating only a minimum number of Long-Term Scenarios, the Commission should also require sensitivity analysis of critical drivers of transmission needs.[1289] In addition, Policy Integrity recommends that the Commission require transmission providers to run a sensitivity for each Long-Term Scenario using a 30-year transmission planning horizon and compare the results with those from the analysis of each Long-Term Scenario using a 20-year transmission planning horizon.[1290] PIOs state that the Commission should specify that, if any critical variable (*e.g.,* natural gas prices, capital costs of wind and solar, short and long duration storage, and carbon capture and sequestration) is the same in more than two Long-Term Scenarios, then transmission providers must conduct sensitivities that use different values for that variable.[1291]

588. Although NRECA does not oppose the proposal that at least one Long-Term Scenario account for high-impact, low-frequency events from extreme weather, NRECA states that the Commission should not require any Long-Term Scenarios to account for possible cyber-attacks. NRECA asserts that modeling cyber-attacks and their effects would be extraordinarily complex and risk disclosure of non-public Critical Electric Infrastructure Information (CEII) and that such risks are better addressed in North American Electric Reliability Corporation standards development, noting that cyber-attacks may already be evaluated under North American Electric Reliability Corporation Transmission Planning Reliability Standard TPL–001–4.[1292]

589. Some commenters oppose requiring one Long-Term Scenario for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events.[1293] LADWP asserts that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single points of failures.[1294] US Chamber of Commerce argues against requiring a Long-Term Scenario for high-impact, low-frequency events because, it asserts, the scope and impacts of such events on the transmission system can be infinite in number.[1295]

590. MISO argues that, although the impacts of large-scale generation loss events associated with extreme weather events should be considered in Long-Term Regional Transmission Planning, the Commission should consider requiring analysis or sensitivities of extreme events that are focused on the times or snapshots when the system is potentially impacted by those events instead of requiring a separate extreme event scenario.[1296] MISO further argues that the Commission should not require a specific number or type of sensitivities, which can vary over time, but instead transmission providers should have flexibility to assess the appropriate sensitivities needed to test scenarios and results at the time those

[1276] Grid United Initial Comments at 5.

[1277] NARUC Initial Comments at 11–12.

[1278] Pattern Energy Initial Comments at 25.

[1279] Vermont Electric and Vermont Transco Initial Comments at 3.

[1280] California Commission Initial Comments at 24–25; Eversource Initial Comments at 18; PJM Initial Comments at 74–75.

[1281] PJM Initial Comments at 75.

[1282] Policy Integrity Initial Comments at 7.

[1283] *Id.* at 6.

[1284] *Id.* at 9 (citing European Commission, Key Cross Border Infrastructure Projects, *https://perma.cc/4U6X-Q2WN* (last visited Aug. 9, 2022)).

[1285] Business Council for Sustainable Energy Initial Comments at 4; NERC Initial Comments at 7; Exelon Initial Comments 7 & n.7; GridLab Initial Comments at 17–19; Idaho Power Initial Comments at 5; Minnesota State Entities Initial Comments at 5; NYISO Initial Comments at 26; PIOs Initial Comments at 23–24; Policy Integrity Initial Comments at 14–16; PPL Initial Comments at 9; R Street Initial Comments at 6; US DOE Initial Comments at 15–16.

[1286] Business Council for Sustainable Energy Initial Comments at 4.

[1287] NERC Initial Comments at 7.

[1288] GridLab Initial Comments at 17–18.

[1289] Policy Integrity Initial Comments at 15.

[1290] *Id.* at 10–11.

[1291] PIOs Initial Comments at 23–24.

[1292] NRECA Initial Comments at 35–36 (citing GDS Associates, Report, at 13 (Aug. 17, 2022); NERC Reliability Standard TPL–001–4, Table 1—Steady State, *https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf*).

[1293] LADWP Initial Comments at 3; MISO Initial Comments at 27–28, 38–39; Mississippi Commission Reply Comments at 6; OMS Initial Comments at 6; US Chamber of Commerce Initial Comments at 7.

[1294] LADWP Initial Comments at 3.

[1295] US Chamber of Commerce Initial Comments at 7.

[1296] MISO Initial Comments at 27–28.

are being developed.[1297] Similarly, OMS argues that analyzing system performance during extreme weather for all Long-Term Scenarios would result in a better understanding of the benefits of transmission and ensure reliability regardless of future changes in generation and/or load.[1298] PIOs likewise recommend that the Commission require that transmission providers model extreme weather events as sensitivities in each Long-Term Scenario and, specifically, that they model at least extreme heat or cold over geographic areas that are experiencing these extremes.[1299]

591. NESCOE states that it supports the study of high-impact, low-frequency events; however, NESCOE argues that the proposal raises questions about whether codifying such a requirement blurs the line between public policy planning and reliability planning, contrary to the NOPR's contention that none of the proposals seek to alter the reliability planning process. NESCOE contends that making the study of high-impact, low-frequency events discretionary instead of mandatory under Long-Term Regional Transmission Planning would avoid such tension.[1300] Mississippi Commission states that the Commission should not mandate that transmission planning attempt to predict extreme weather events and over-build the system, because ''predicting where the next hurricane or tornado will land is speculative.'' Mississippi Commission argues that a better approach is to incorporate construction standards (*e.g.,* North American Electric Reliability Corporation, IEEE, local reliability criteria) designed to withstand such events.[1301]

592. Idaho Power raises concerns that developing multiple sensitivities for multiple Long-Term Scenarios over a long-term transmission planning horizon introduces too many variables.[1302] Minnesota State Entities state that defining specific methods in the final order—such as the difference between a ''sensitivity'' and what is included in a ''scenario''—can be unnecessarily confusing and complex.[1303] US DOE encourages transmission providers to perform sensitivity analyses but states that the Commission should only require that one Long-Term Scenario analyze high-impact, low-frequency events.[1304]

c. Commission Determination

593. We modify the NOPR proposal to require transmission providers in each transmission planning region to develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1305] As discussed below, we acknowledge support in the record for studying high-impact, low-frequency events as proposed in the NOPR[1306] but also recognize that requiring a fourth Long-Term Scenario might be a burdensome way to study such events as compared to a sensitivity.[1307] We find that more clearly defining the type of system conditions that transmission providers must model to account for uncertain operational outcomes—in particular, multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area—compared to the NOPR proposal, will enable transmission providers to better account for periods when regional transmission facilities may have particularly high value by decreasing the risk of loss of load and/or decreasing the cost to reliably serve load.

594. Therefore, we require that, after developing at least three Long-Term Scenarios, transmission providers develop a sensitivity for each of the Long-Term Scenarios.[1308] We provide transmission providers with flexibility to conduct this sensitivity either before or after identifying potential regional transmission solutions to the Long-Term Transmission Needs identified using those Long-Term Scenarios. Conducting this sensitivity before identifying potential regional transmission solutions can be useful because it may help transmission providers to identify such solutions. On the other hand, conducting this sensitivity after identifying potential regional transmission solutions to Long-Term Transmission Needs would allow transmission providers to engage in efforts to develop additional or alternative regional transmission solutions to address such conditions.

595. In conducting this sensitivity, transmission providers change the data inputs of the underlying Long-Term Scenarios—in terms of load, generation, generator outages, and transmission outages—to account for uncertain operational outcomes that determine the benefits of or need for regional transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area, while maintaining the underlying longer-term determinants of the Long-Term Scenario (*e.g.,* the installed capacity of each generation resource). The sensitivity can be thought of as a ''stress test'' for all Long-Term Scenarios.

596. We find it necessary to require the consideration of a more narrowly defined set of conditions, as compared to the broader high-impact, low-frequency event conditions described in the NOPR, to include multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1309] Extreme weather events have occurred more frequently in recent years,[1310] are periods when regional transmission facilities have particularly high value,[1311] and create system conditions that transmission providers can readily specify compared to contingencies with an unknown root cause.[1312] During these extreme weather

[1297] *Id.* at 39.

[1298] OMS Initial Comments at 6.

[1299] PIOs Initial Comments at 21.

[1300] NESCOE Initial Comments at 32–33.

[1301] Mississippi Commission Reply Comments at 6.

[1302] Idaho Power Initial Comments at 5.

[1303] Minnesota State Entities Initial Comments at 5.

[1304] US DOE Initial Comments at 16.

[1305] The Commission proposed in the NOPR to require that at least one of four Long-Term Scenarios account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. NOPR, 179 FERC ¶ 61,028 at P 124.

[1306] *See, e.g.,* New England for Offshore Wind Initial Comments at 2; *see also* Arizona Commission Initial Comments at 6–7. We also note that the Commission has previously discussed that ''[e]xtreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future.'' Order No. 896, 183 FERC ¶ 61,191 at P 2.

[1307] *See, e.g.,* MISO Initial comments at 27.

[1308] *See* NOPR, 179 FERC ¶ 61,028 at P 125 n.229. A sensitivity represents a single assumption about a short-term input or factor (some input with a value that may change throughout a day or year). A scenario represents an assumption about a longer-term input or factor (*e.g.,* resource retirements and additions or public policies).

[1309] *See, e.g.,* Grid United Initial Comments at 4–5 (stating that ''the Commission should define or provide examples of the low-frequency, high impact events that it would like to be considered for planning purposes'').

[1310] *See supra* The Overall Need for Reform section; *see also* NOPR, 179 FERC ¶ 61,028 at P 45; Breakthrough Energy Initial Comments at 8.

[1311] *See* ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5–6.

[1312] In terms of specifying the system conditions during extreme weather events, transmission providers can, for example, look at previous severe cold weather events to identify how load might increase, how load and generation forecasts might be incorrect, and how generation and transmission outages might occur during a future extreme weather event.

events, generation and transmission outages can be widespread, occur at the same time, and persist due to a common cause like freezing temperatures or limited fuel availability. This more narrowly defined set of conditions also gives transmission providers more direct guidance on how to comply with the requirements of this final order.[1313]

597. Although we are only requiring that one sensitivity analysis specific to extreme weather events be applied to each Long-Term Scenario to comply with this final order, we do not preclude transmission providers from considering additional sensitivities. We recognize that transmission providers may consider several other sensitivities as important and helpful in evaluating the benefits of and need for Long-Term Regional Transmission Facilities. For example, transmission providers can develop sensitivities to account for a cyber-attack, significant forecast error, or fuel price volatility. We encourage transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.

598. We find that modeling extreme weather events as sensitivities is appropriate for Long-Term Regional Transmission Planning. We first note that extreme weather events can occur under any assumed future scenario but do not, by themselves, represent changes in the way that factors are used in Long-Term Scenarios to determine Long-Term Transmission Needs.[1314] Therefore, we believe that applying a sensitivity to each Long-Term Scenario is a more accurate way to evaluate the effects of high-impact, low-frequency events than considering such events in a distinct Long-Term Scenario. Second, although there is a burden associated with conducting sensitivities, the overall burden of conducting a sensitivity analysis is comparatively lower than that of developing a new, separate Long-Term Scenario. This is because sensitivities will be conducted using the existing Long-Term Scenarios, where most inputs, and the factors and assumptions used to develop the scenarios, have already been established and mapped. Adjusting a set of existing inputs to test the impact of the changes on a Long-Term Scenario through a sensitivity analysis is therefore less burdensome than developing an entirely new Long-Term Scenario.

599. In addition, we highlight that transmission providers can use the required sensitivity analyses to evaluate the need for, or benefits of, increased Interregional Transfer Capability provided by candidate Long-Term Regional Transmission Facilities. We recognize that certain Long-Term Regional Transmission Facilities could increase Interregional Transfer Capability by changing the topology of the transmission system, even if the specific transmission facility is not directly connected to a neighboring transmission planning region's transmission system. We believe that an increase in Interregional Transfer Capability could provide significant benefits during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages.[1315] We note that several commenters discuss the need for greater Interregional Transfer Capability because of extreme weather events[1316] and the importance of modeling extreme weather event conditions to capture the benefits of regional transmission facilities.[1317] As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to consider increased Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility when measuring Benefit 6.[1318] We believe that transmission providers can evaluate Benefit 6, including reduced loss of load and reduced production costs during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages, using this required sensitivity, among other sensitivities that transmission providers may develop to capture extreme events and system contingencies.

600. We disagree with NESCOE's concern that a requirement to study the impact of high-impact, low-frequency events might ''blur[] the line between public policy planning and reliability planning.'' [1319] Rather, as discussed below in the Evaluation of the Benefits of Regional Transmission Facilities section, we believe that the requirement complements Benefit 6 (Mitigation of Extreme Weather Events and Unexpected System Conditions) given the high probability that extreme weather events will cause unplanned transmission outages and the likelihood that such events will continue to occur at regular intervals.[1320] Although this final order requires a more comprehensive consideration of benefits, it does not alter Order No. 1000's requirements for transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the transmission planning region's reliability and economic requirements.

601. We also acknowledge LADWP's concern that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single point failure.[1321] Although we do not preclude transmission providers from conducting such a study, such a study would not meet the final order's requirement to conduct a sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.

7. Specificity of Data Inputs

a. NOPR Proposal

602. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to use ''best available data inputs'' when developing Long-Term Scenarios.[1322] The Commission stated that, by ''best available,'' the Commission did not imply that there is a single ''best'' value for each data input that transmission providers must use, but rather that best practices are used to develop that data input.[1323]

603. The Commission proposed to define ''best available data inputs'' as data inputs that are timely and developed using diverse and expert perspectives, adopted via a process that satisfies the Order Nos. 890 and 1000 transparency transmission planning principles described above, and reflect

[1313] *See, e.g.,* Grid United Initial Comments at 4–5.

[1314] *See* MISO Initial Comments at 27–28; OMS Initial Comments at 6.

[1315] *See, e.g.,* Order No. 896, 183 FERC ¶ 61,191 at PP 85–88.

[1316] BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Kansas Commission Initial Comments at 8–9; NARUC Initial Comments at 23; US DOE Initial Comments at 39–42; *see also* ELCON Initial Comments at 8 (arguing Interregional Transfer Capability should be a driver of transmission needs); PJM Initial Comments at 66–67.

[1317] *See* ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5–6.

[1318] *See infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

[1319] NESCOE Initial Comments at 33.

[1320] *See infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

[1321] LADWP Initial Comments at 3.

[1322] NOPR, 179 FERC ¶ 61,028 at PP 130–134.

[1323] *Id.* P 130.

the list of factors that transmission providers must incorporate into Long-Term Scenarios.[1324] The Commission explained that an example of data inputs that could meet this requirement are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. The Commission stated that another example of data inputs that could meet this requirement are the most recent data on renewable energy potential and distributed energy resources developed by national labs.[1325]

604. The Commission proposed to require transmission providers in each transmission planning region to update all data inputs each time they reassess and revise, as necessary, their Long-Term Scenarios, which, as explained in the NOPR, the Commission proposed to require that they do at least every three years. As indicated in the Long-Term Regional Transmission Planning section of the NOPR,[1326] the Commission also proposed to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process through which transmission providers determine which data inputs to use in their Long-Term Scenarios. For example, consistent with the coordination transmission planning principle established in Order No. 890, the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input concerning which data inputs to use in Long-Term Scenarios.[1327]

605. The Commission preliminarily found that a requirement to use the best available data inputs was necessary to ensure that transmission providers are regularly updating data inputs and then using timely and accurate data inputs to inform Long-Term Scenarios. The Commission stated that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, the Commission explained that data inputs can directly affect which transmission facilities may be selected and, in turn, Commission-jurisdictional rates.[1328]

b. Comments

i. Interest in Best Available Data Requirement

606. Many commenters generally support the NOPR proposal for ''best available data,'' but some recommend that the Commission monitor data inputs.[1329] AEE states that it is not practical to make a more prescriptive requirement for data inputs than the NOPR proposal and recommends that the Commission be vigilant in monitoring data inputs.[1330] Policy Integrity states that the NOPR proposal is crucial in protecting against strategic modeling behavior.[1331] WATT Coalition adds that ''best available data'' on future generation must be used because demand and energy profiles are inherently uncertain.[1332]

607. ACEG claims that the FPA supports the Commission's proposed requirement to plan based on the best available data, noting that section 217(b)(4) requires the Commission to exercise its authority ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligation of load-serving entities.'' [1333] ACEG argues that load-serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies.[1334]

608. Clean Energy Buyers state that it is important to get stakeholder input on data inputs, as has been done through MISO's Long-Range Transmission Planning effort.[1335] Breakthrough Energy states that Long-Term Scenarios should use ''best available data.'' [1336]

ii. Reservations with the Best Available Data Requirement

609. Several commenters support the NOPR proposal but nevertheless have suggestions about how to modify the proposal.[1337] For example, several commenters request that the Commission create a common dataset, publish a database of best available sources of data, or otherwise standardize data inputs.[1338] Southeast PIOs state that the Commission should publish a regularly updated database of best available data sources and require transmission providers to justify any decision not to use that database, arguing that flexibility in project selection can only work if the selection process utilizes reliable and standardized inputs.[1339] SEIA urges the Commission to issue standards or guidelines that define what constitutes ''best available data inputs'' for each of the seven categories of factors.[1340] R Street contends that intraregional standardization could support internal consistency and transparency and focus scarce stakeholder capital.[1341]

610. ELCON notes that, as part of the three-year reassessment of Long-Term Scenarios, the Commission may decide that identifying or standardizing data inputs and sources may help to ensure that transmission providers are consistently using timely and widely accepted data.[1342] Interwest endorses US DOE's proposal in its comments to the ANOPR to standardize data inputs.[1343] ACORE states that an identification of certain common data sets and modeling best practices will reduce uncertainty, improve transparency, and achieve greater consistency among transmission planning regions.[1344]

611. ENGIE states that data inputs should be sourced from Federal and state agencies whenever possible.[1345] Renewable Northwest states that determining a future resource mix for NorthernGrid is possible with publicly available data.[1346] GridLab states that the Commission should consider whether to require that transmission providers either use unadjusted, publicly available data in Long-Term Regional Transmission Planning or justify why using proprietary data would provide superior results.

612. Several commenters state that it is not necessary for the Commission to facilitate the development of data or

[1324] *Id.* P 131.

[1325] *Id.* P 131 n.247.

[1326] *Id.* PP 64–67.

[1327] *Id.* P 132.

[1328] *Id.* P 133.

[1329] AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People's Counsel Initial Comments at 14; Duke Initial Comments at 16–17; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ITC Initial Comments at 12; NARUC Initial Comments at 13–15; NRECA Initial Comments at 35–36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 6; US DOE Initial Comments at 16–17; WATT Coalition Initial Comments at 7.

[1330] AEE Initial Comments at 23.

[1331] Policy Integrity Initial Comments at 17.

[1332] WATT Coalition Initial Comments at 7.

[1333] ACEG Initial Comments at 26–27 (citing 16 U.S.C. 824q(b)(4)).

[1334] *Id.* at 27.

[1335] Clean Energy Buyers Initial Comments at 18.

[1336] Breakthrough Energy Supplemental Comments at 1.

[1337] ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; Eversource Initial Comments at 20–21; GridLab Initial Comments at 23; OMS Initial Comments at 5; Pine Gate Initial Comments at 27–29; PIOs Initial Comments at 19–20; Policy Integrity Initial Comments at 6, 16–18; Southeast PIOs Initial Comments at 47–48.

[1338] ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; GridLab Initial Comments at 23; PIOs Initial Comments at 19–20; Southeast PIOs Initial Comments at 47–48.

[1339] Southeast PIOs Initial Comments at 47.

[1340] SEIA Initial Comments at 11; SEIA Reply Comments at 4.

[1341] R Street Initial Comments at 7.

[1342] ELCON Initial Comments at 13.

[1343] Interwest Initial Comments at 8 (citing US DOE ANOPR Initial Comments at 12–15).

[1344] ACORE Reply Comments at 5.

[1345] ENGIE Initial Comments at 3.

[1346] Renewable Northwest Initial Comments at 17.

standardize inputs.[1347] PPL, for example, asserts that the task of developing data inputs should be left to transmission providers, with the caveat that the entire process should avoid hindsight bias or an inappropriate shift in burden or responsibility to the transmission provider.[1348] SPP states that the development of data inputs facilitated by the Commission could provide value if implemented in a way that does not create additional burden to the assessment. SPP suggests that allowing access to recommended data sources or standard information would provide an additional reference for transmission providers to validate their own data, incorporate portions of the data, or utilize all of the data, as appropriate.[1349]

613. US Climate Alliance and US DOE support transparency requirements for data inputs.[1350] Similarly, California Commission and NRECA support transparency requirements for data inputs, subject to appropriate confidentiality considerations.[1351] Colorado Consumer Advocate contends that greater transparency and opportunities for meaningful stakeholder input regarding data inputs for Long-Term Regional Transmission Planning will improve the regional transmission planning process and help to ensure that Order No. 890 transmission planning principles are met.[1352]

614. Concerned Scientists state that the final order should require transmission providers and load-serving entities to submit to the relevant transmission planner an account of planned investments and retirements over the transmission planning horizon because not doing so ensures a transmission planning process that is less informed than it can and should be. Concerned Scientists state that excluding these minimum requirements from the final order will inevitably lead to the exclusion of information needed by regulators, stakeholders, and the transmission providers themselves to make informed investment decisions.[1353] PJM, which supports the NOPR proposal, states that, while it is important to consider resource retirements when developing planning assumptions, generation retirement forecasts may be interpreted by stakeholders as sending economic signals concerning the viability of existing generating units. Thus, PJM urges the Commission to provide clear direction on how to balance the heightened transparency and public processes proposed in the NOPR with appropriate safeguards against releasing data that could preempt unit owner economic decisions, as well as decisions by market participants.[1354]

615. ITC, PJM, and SEIA support the NOPR proposal, and ITC and SEIA agree with PJM's suggestion that the Commission hold regular forums, workshops, or technical conferences to determine best practices in developing best available data.[1355]

616. SPP Market Monitor contends that the Commission should further provide guidance in the form of parameters by which transmission providers should define the phrase ''best available data,'' which SPP Market Monitor argues would aid in ensuring that the Long-Term Scenarios studied and transmission projects or facilities planned are consistent and reasonable.[1356] Relatedly, Pine Gate states that the NOPR's failure to address source accuracy in the definition of best available date inputs may introduce subjectivity into Long-Term Regional Transmission Planning, obscure sources, and inhibit the ability of stakeholders to meaningfully engage in the Long-Term Regional Transmission Planning process. To remedy these concerns, Pine Gate suggests that the Commission define ''best available data inputs'' as data inputs that: (1) are current and developed using diverse and expert perspectives expressed during a stakeholder process; (2) have identified sources; (3) are adopted via a process that satisfies Order No. 890's transparency planning principle; and (4) reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios.[1357] Policy Integrity states that the Commission should require external vetting of data inputs used by a party without a stake in the outcomes.[1358]

617. Several commenters state that the final order should add a requirement that data must be accurate.[1359] ELCON notes that utilities should consider whether a data source's historical projections ultimately proved to be accurate when identifying ''best available'' inputs, and Vermont Electric and Vermont Transco agree.[1360] Arizona Commission supports the use of relevant, timely, and accurate data.[1361]

618. LADWP asserts that the determination of ''best available data'' should be changed to ''the most accurate data inputs available'' at the time of study because ''best'' is subjective but ''most accurate'' is clear and objective. LADWP states that, if data is interpreted differently, as may be the case under the ''best available'' standard, then results will be inconsistent. For example, LADWP states that the ''most accurate data inputs available'' for load inputs for near-term planning and for data for generation and energy storage capacities would be data derived from projections based on actual field measurements, and from in-service equipment (instead of from manufacturing brochures or articles), respectively. LADWP states that for new technologies, the projected availability and performance parameters should be based on actual data when possible. For example, LADWP states that data derived from field operating experience with prototypes should be considered ''most accurate'' as compared to lab test data. LADWP contends that transmission providers should be careful not to take ''expert perspectives'' at face value, but should seek to use data inputs that show a strong correlation to scientifically verifiable facts. Furthermore, LADWP states, projected data based on administrative law or executed interconnection agreements should be considered more certain, and hence more accurate, than data based on corporate or government goals.[1362]

619. GridLab recommends that the Commission request that the national laboratories and other public agencies work with transmission providers, resource developers, and others to evaluate the historical accuracy of publicly available data sources.[1363] However, Ameren sees no reason to expand the definition of best available data inputs to include an evaluation of data source entities' historical accuracy identifying and projecting trends

[1347] Ameren Initial Comments at 14–15; Idaho Power Initial Comments at 5; NESCOE Initial Comments at 35–36; New York State Department Initial Comments at 8–9; PPL Initial Comments at 10.

[1348] PPL Initial Comments at 10.

[1349] SPP Initial Comments at 11–12.

[1350] US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 17.

[1351] California Commission Initial Comments at 25; NRECA Initial Comments at 35–37 (citing GDS Associates, Report, at 13 (Aug. 17, 2022)).

[1352] Colorado Consumer Advocate Initial Comments at 26.

[1353] Concerned Scientists Reply Comments at 17.

[1354] PJM Reply Comments at 22.

[1355] ITC Initial Comments at 12; PJM Initial Comments at 76–77; SEIA Initial Comments at 11; SEIA Reply Comments at 4–5.

[1356] SPP Market Monitor Initial Comments at 8.

[1357] Pine Gate Initial Comments at 28.

[1358] Policy Integrity Initial Comments at 17–18.

[1359] ELCON Initial Comments at 13; LADWP Initial Comments at 4; Vermont Electric and Vermont Transco Initial Comments at 3.

[1360] ELCON Initial Comments at 13; Vermont Electric and Vermont Transco Initial Comments at 3.

[1361] Arizona Commission Initial Comments at 7.

[1362] LADWP Initial Comments at 4.

[1363] GridLab Initial Comments at 24.

because the open and transparent planning process of diverse stakeholders will identify any questionable or non-reliable data sources.[1364]

620. ELCON states that the Commission may need to clarify what data is considered ''timely'' and argues, for example, that the Commission should not establish a mandate in favor of using historical data (*e.g.,* actual data from the previous 12 months) because such data may not reflect current and future operational needs.[1365] Pine Gate is concerned that the use of the term ''timely'' in the definition of ''best available data inputs'' may lead to confusion and inconsistency amongst transmission providers.[1366]

621. PJM Market Monitor states that both aggregate and very specific locational data on future demand and the future resource mix will be critical for efficient and cost-effective transmission planning.[1367]

iii. Concerns With Best Available Data

622. Several commenters either oppose the NOPR proposal or object to specific aspects of the NOPR proposal.[1368] Ameren, EEI, and PPL state that the NOPR proposal is unnecessary and too prescriptive.[1369] Idaho Commission agrees that it is too prescriptive.[1370] EEI states that, while using the best available data inputs when preparing the Long-Term Scenarios is appropriate, a *pro forma* definition may not be necessary.[1371]

623. PPL expresses concern that the proposed requirement for data inputs will unnecessarily burden transmission providers by effectively shifting a burden from data owners (who are in the best position to control and ensure data accuracy) to the transmission provider and instead recommends that the Commission strengthen the requirements applicable to the data owners or data source entities.[1372] Dominion states that using best available data inputs should not be a requirement because transmission providers should be permitted to select the data inputs that are most appropriate for their own situation, as they know their transmission systems best. Dominion additionally does not support defining ''best available data inputs'' as proposed because it would limit transmission providers' flexibility to conduct transmission planning that is most appropriate to their unique system needs.[1373]

624. MISO, Utah Division of Public Utilities, and Xcel state that the NOPR proposal on data inputs is a potential source of conflict.[1374] MISO is concerned that parties opposing particular long-range transmission planning outcomes could seize on the proposed language and argue that some other data was the best available data, thereby delaying the process; and the resulting disputes could potentially slow down the transmission planning process and ultimately delay much needed transmission.[1375] Xcel agrees.[1376] Utah Division of Public Utilities attests that requiring transmission providers to use the best data available is not based on evidence showing that data inputs currently used by transmission providers have led to unjust or discriminatory rates, and may produce unnecessary and time-consuming disagreements among stakeholders regarding which data inputs to use.[1377] National Grid asserts that the term ''best available'' data is vague and subjective, which introduces development, regulatory and implementation inefficiencies.[1378] Clean Energy Associations argue that transmission providers should be required to explain the number and the basis for including each input they choose to include.[1379]

iv. Flexibility Issues

625. Several commenters, some that support the NOPR proposal and some that do not, call for flexibility in allowing transmission providers to determine what constitutes best available data. ISO–NE and NYISO support the NOPR proposal but request that the Commission provide transmission providers with some flexibility about how to satisfy this requirement.[1380] ISO–NE asserts that the Commission should allow flexibility for ISO–NE to rely on the states to determine the data inputs, with its technical support and stakeholder input, and NESCOE, which opposes the NOPR proposal, agrees.[1381] NESCOE is concerned about the prescriptive nature of the NOPR proposal and contends that data inputs should be determined on a region-by-region basis by transmission providers with input from states and stakeholders.[1382] MISO agrees on both points.[1383] Duke, which generally supports the NOPR proposal to define best available data inputs and requirement to follow a transparent process to develop the data inputs, states that because there is not a single ''best'' value for each input, the emphasis should be on best practices to develop the data inputs, which should be left to the regions to develop with their specific stakeholders.[1384]

626. In addition, NYISO requests that the Commission revise the definition of best available data to permit flexibility on how it reflects factors considered in the scenarios. Specifically, NYISO requests that the language in the NOPR specifying that the data inputs must ''reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios'' should be modified to ''reflect the factors that the transmission provider considers in the scenarios'' to reflect the authority of transmission planning regions to identify which factors should be used in Long-Term Scenarios. NYISO adds that transmission providers should have authority over how to interpolate and employ their data sets.[1385]

627. MISO, which opposes the NOPR proposal, contends that the Commission should allow transmission providers to determine, in consultation with its stakeholders, what data is most appropriate, but require transmission providers to use the most up-to-date data from the source that they select.[1386] MISO recommends that, if the final order includes the NOPR proposal for best available data, then the Commission should clarify that transmission providers may satisfy the requirement by using the most up-to-date data that they have selected and that reflects practical limitations

[1364] Ameren Initial Comments at 15.

[1365] ELCON Initial Comments at 13.

[1366] Pine Gate Initial Comments at 28.

[1367] PJM Market Monitor Initial Comments at 4.

[1368] Ameren Initial Comments at 14–15; Dominion Initial Comments at 26–28; EEI Initial Comments at 14; ELCON Initial Comments at 13; Idaho Power Initial Comments at 5; LADWP Initial Comments at 4; MISO Initial Comments at 40–41; MISO TOs Initial Comments at 18–19; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 35–36; PPL Initial Comments at 9–10; R Street Initial Comments at 7; Vermont Electric and Vermont Transco Initial Comments at 3; Xcel Initial Comments at 10.

[1369] Ameren Initial Comments at 14–15; EEI Initial Comments at 14; PPL Initial Comments at 9.

[1370] Idaho Commission Initial Comments at 3.

[1371] EEI Initial Comments at 14.

[1372] PPL Initial Comments at 9–10.

[1373] Dominion Initial Comments at 26–27.

[1374] MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

[1375] MISO Initial Comments at 40.

[1376] Xcel Initial Comments at 10.

[1377] Utah Division of Public Utilities Initial Comments at 6.

[1378] National Grid Initial Comments at 14.

[1379] Clean Energy Associations Initial Comments at 13.

[1380] ISO–NE Initial Comments at 28; NYISO Initial Comments at 28.

[1381] ISO–NE Initial Comments at 28; NESCOE Initial Comments at 35–36.

[1382] NESCOE Initial Comments at 36.

[1383] MISO Initial Comments at 40.

[1384] Duke Initial Comments at 16–17.

[1385] NYISO Initial Comments at 28.

[1386] MISO Initial Comments at 40.

regarding the precision and scope of the data.[1387] MISO TOs suggest that the Commission consider articulating principles and guidelines and let transmission planning regions develop their own conception of ''best available data'' in the interest of flexibility.[1388] Nevada Commission states that the definition of ''best available data'' may need further comment and will likely evolve as the Long-Term Regional Transmission Planning process is implemented.[1389]

628. National Grid requests that the Commission clarify that transmission providers have final and sole responsibility and discretion to determine what is ''best available data'' as transmission providers are best situated to make these determinations in consultation with their stakeholders. National Grid also seeks clarity from the Commission as to what ''diverse'' means as it describes best available data inputs. National Grid further asserts that the Commission should distinguish between Long-Term Scenarios based on diverse inputs in each scenario.[1390]

v. Best Sources of Data Issues

629. Several commenters, some that support the NOPR proposal and some that do not, make suggestions about the best sources of data. Several commenters state that transmission providers already have the best available data.[1391] Nebraska Commission further states that the current methods used by RTOs/ISOs would meet the NOPR's proposed requirements.[1392] PPL states that transmission providers already use a ''best available data inputs'' standard in transmission planning but must rely on other entities' data.[1393] EEI states that, if the Commission adopts a definition for best available data, it should acknowledge that transmission providers and load-serving entities often may possess this data.[1394]

630. Several commenters state that load-serving entities have the best available data.[1395] Eversource recommends that the Commission require the RTOs/ISOs to collaborate with the transmission owners regarding transmission owners' forecast of load localized peak times.[1396] PIOs state that the Commission should require load-serving entities to provide their generation and load forecasts to transmission providers so that they have reasonable information to use and do not have to perform their own estimates.[1397] ACEG and Clean Energy Associations agree.[1398]

631. Western PIOs state that the Western Electricity Coordinating Council databases on load and generation forecasts and the Western Electricity Coordinating Council Anchor dataset constitute best available data.[1399] NARUC argues that any reasonable, credible source of data should be allowed to supplement more traditional sources like the national laboratories and RTO/ISO-generated data.[1400] SREA recommends that, to the extent possible, the Commission should recognize the National Renewable Energy Lab's Annual Technology Baseline (NREL ATB) as the Nation's preferred data set.[1401] Policy Integrity states that the Commission should urge transmission providers to engage independent researchers in the process to ensure inclusion of the latest modeling and computational developments.[1402] PIOs state that the Commission could publish a regularly updated list of databases that meet the ''best available data requirement,'' such as the following current databases: NREL ATB data, US DOE's Annual Energy Outlook for fuel costs, and NREL's Electrification Futures Study for electrification trends. PIOs suggests that the Commission could additionally partner with the US DOE and National Laboratories to develop appropriate databases.[1403]

632. Entergy asserts that integrated resource plans approved by retail commissions should be considered the best available data, and Louisiana Commission and Mississippi Commission agree.[1404] However, Kentucky Commission Chair Chandler disagrees with the propositions that local data provided by a utility in an integrated resource plan is superior to other data and that RTOs/ISOs should be required to rely on such data.[1405]

c. Commission Determination

633. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use ''best available data inputs'' when developing Long-Term Scenarios. As the Commission explained in the NOPR, by ''best available,'' we do not imply that there is a single ''best'' value for each data input that transmission providers must use, but rather that best practices will be used to develop each data input. We adopt, with modification, the NOPR proposal to define ''best available data inputs'' as data inputs that are timely, developed using best practices and diverse and expert perspectives,[1406] and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000.[1407] We further adopt the NOPR proposal to require that best available data inputs also reflect the list of factors that transmission providers account for in their Long-Term Scenarios.[1408] By ''reflect the list of factors,'' we mean the data inputs that correspond to the list of factors that transmission providers have determined might affect Long-Term Transmission Needs.[1409] We also adopt the NOPR proposal to require transmission providers to update, as necessary, all data inputs each time they reassess and revise their Long-Term Scenarios.

634. Finally, in addition, we adopt the NOPR proposal to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process

[1387] *Id.* at 29.

[1388] MISO TOs Initial Comments at 19.

[1389] Nevada Commission Initial Comments at 9.

[1390] National Grid Initial Comments at 14.

[1391] EEI Initial Comments at 14; Nebraska Commission Initial Comments at 6; PJM Initial Comments at 76; PPL Initial Comments at 9–10.

[1392] Nebraska Commission Initial Comments at 6.

[1393] PPL Initial Comments at 9–10.

[1394] EEI Initial Comments at 14.

[1395] *Id.;* Eversource Initial Comments at 20; Xcel Initial Comments at 10.

[1396] Eversource Initial Comments at 20.

[1397] PIOs Initial Comments at 19.

[1398] ACEG Reply Comments at 23; Clean Energy Associations Reply Comments at 7.

[1399] Western PIOs Initial Comments at 31.

[1400] NARUC Initial Comments at 13.

[1401] SREA Reply Comments at 26.

[1402] Policy Integrity Initial Comments at 17.

[1403] PIOs Initial Comments at 19.

[1404] Entergy Initial Comments at 18; Louisiana Commission Reply Comments at 7; Mississippi Commission Reply Comments at 9.

[1405] Kentucky Commission Chair Chandler Reply Comments at 3.

[1406] While we largely adopt the definition of ''best available data inputs'' proposed in the NOPR, we modify it to reflect the requirement that ''best available data inputs'' are developed using best practices.

[1407] For example, the transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

[1408] One example of a data input dataset that would meet the requirement for best available data are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. Another example of a data input dataset that would meet the requirement for best available data is the most recent data on renewable energy potential and distributed energy resources developed by national labs.

[1409] For example, a transmission provider might determine that corporate goals for corporations less than $20 million are too small to affect Long-Term Transmission Needs and not include these corporate goals in its Long-Term Scenarios. This transmission provider does not have any obligation to develop data inputs corresponding to these omitted corporate goals.

through which transmission providers determine which data inputs to use in their Long-Term Scenarios. Consistent with the coordination transmission planning principle established in Order No. 890, we also adopt the NOPR proposal to require transmission providers in each transmission planning region to give stakeholders an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning which data inputs to use in Long-Term Scenarios.[1410] Also, we clarify that the right to challenge data inputs via dispute resolution as discussed in Order No. 890 is available for interested parties with respect to data inputs that transmission providers develop for Long-Term Regional Transmission Planning.[1411]

635. We agree, in part, with NYISO's suggestion to revise the wording of the NOPR proposal that required best available data to reflect "the list of factors that transmission providers must incorporate into Long-Term Scenarios." [1412] NYISO states that the NOPR language should be modified to "reflect the factors that the public utility transmission provider considers in the scenarios." [1413] As discussed in the Categories of Factors section of this final order, we explain that transmission providers need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs. We find that transmission providers must use best available data when determining whether each factor is likely to affect Long-Term Transmission Needs. Once transmission providers have determined that a factor is likely to affect Long-Term Transmission Needs, they must use the best available data when they then account for that factor in the development of Long-Term Scenarios.

636. We find that a requirement to use the best available data inputs is warranted to ensure that transmission providers are regularly updating data inputs and using timely and accurate data inputs to inform Long-Term Scenarios. We further find that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, we find that data inputs affect transmission providers' ability to identify Long-Term Transmission Needs and thus affect the ability to identify, evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. We note that many commenters share this view and support the NOPR proposal.[1414]

637. We disagree with commenters asserting that the requirements for data inputs would be overly burdensome to transmission providers.[1415] We believe that, because most transmission providers already endeavor to use best available data inputs to ensure credible results in regional transmission planning, this final order's requirements for data inputs will not impose an unreasonable burden beyond existing practices today. Further, as many commenters note,[1416] any increase in transmission providers' burden from such requirements is outweighed by the benefits of establishing reasonable safeguards for accuracy and confidence in Long-Term Regional Transmission Planning.

638. We disagree with commenters' arguments that the final order requirements for data inputs would lead to problems because stakeholders will delay Long-Term Regional Transmission Planning by contesting the data used by transmission providers.[1417] Similarly, we disagree with commenters' arguments that the requirements for data inputs unnecessarily limit transmission providers' flexibility in producing data inputs.[1418] As discussed above, this final order establishes requirements for data inputs used in Long-Term Scenarios and requires that stakeholders have an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning those data inputs. However, transmission providers have significant flexibility about which data inputs they use in Long-Term Scenarios, and no commenters have provided us with convincing or specific arguments that stakeholder input will undermine that flexibility or cause consequential delays to the Long-Term Regional Transmission Planning process.

639. We decline to adopt the suggestion of commenters to standardize data inputs used by transmission providers in Long-Term Regional Transmission Planning.[1419] Imposing further requirements to enforce uniformity in data is challenging given regional variation in transmission planning approaches. Further, it might stifle innovation that would improve Long-Term Regional Transmission Planning.

640. We decline to adopt the modifications of the NOPR proposal suggested by certain commenters to establish specific accuracy standards in addition to requiring that transmission providers use best available data inputs.[1420] While we agree that transmission providers should strive for data accuracy, including by assessing the historical accuracy of different data sources where appropriate, a specific accuracy standard would be difficult to develop and administer given the diversity of different data inputs.[1421] As we explain above, transmission providers must use best available data inputs, which include forecasted data, and must develop such inputs using diverse and expert perspectives. They must use best practices to develop data inputs, and must do so in an open and transparent stakeholder process. Taken together, we believe that these

[1410] NOPR, 179 FERC ¶ 61,028 at P 132.

[1411] Order No. 890, 118 FERC ¶ 61,119 at PP 501–503.

[1412] NYISO Initial Comments at 28 (citing NOPR, 179 FERC ¶ 61,028 at P 131).

[1413] *Id.*

[1414] ACORE Initial Comments at 8; AEE Initial Comments at 22; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO–NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34–35; NARUC Initial Comments at 13–15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16–17; US DOE Initial Comments at 16–18; WATT Coalition Initial Comments at 7.

[1415] Ameren Initial Comments at 14; MISO Initial Comments at 29; PPL Initial Comments at 9–10; Utah Division of Public Utilities Initial Comments at 7; Xcel Initial Comments at 10.

[1416] *See* ACORE Initial Comments at 8; AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO–NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34–35; NARUC Initial Comments at 13–15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16–17; US DOE Initial Comments at 16–18; WATT Coalition Initial Comments at 7.

[1417] MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

[1418] Dominion Initial Comments at 26–27; Duke Initial Comments at 16–17; MISO Initial Comments at 40; MISO TOs Initial Comments at 19; NESCOE Initial Comments at 35–36.

[1419] ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; GridLab Initial Comments at 23; PIOs Initial Comments at 19–20; Southeast PIOs Initial Comments at 47–48.

[1420] ELCON Initial Comments at 13; LADWP Initial Comments at 4; Pine Gate Initial Comments at 27–29; Vermont Electric and Vermont Transco Initial Comments at 3.

[1421] In addition, while we decline to adopt a specific accuracy standard that data must meet in order to be "best available data," we note that a demonstration that a data source has historically proven to be relatively inaccurate would likely constitute evidence that such data is not best available data.

requirements will help ensure that data inputs are as accurate as possible, while also providing transmission providers with the flexibility to use best practices to develop data inputs that are appropriate for their transmission planning regions and to recognize the inherent uncertainty involved in planning transmission on a forward-looking basis.

641. With respect to the issue raised by PJM about revealing potentially confidential data to improve accuracy,[1422] we reiterate, as discussed above, that consistent with Order No. 890's transparency transmission planning principle, transmission providers in each transmission planning region are required to disclose (subject to appropriate confidentiality protections) information and data inputs they use to create each Long-Term Scenario.[1423] The Commission has recognized that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.[1424] The Commission has also noted that using resource-specific data that best reflect actual operations on the transmission system leads to more precise and effective transmission study results. In addition, the Commission has recognized that market participants who provide that information need to be assured that the confidential information they provide will be used for its intended purpose in planning the transmission system and will not be disclosed in a manner that harms them commercially. However, the Commission has found that, at the same time, the requirement in Order No. 890 for transmission providers to disclose to all customers and other stakeholders the basic methodology, criteria, assumptions, and data that underlie their transmission system plans to enable customers, other stakeholders, or an independent third-party to replicate the results of planning studies is essential to an open and transparent transmission planning process.[1425] Thus, the Commission has found that, without certain generator dispatch and economic information, for example, it becomes difficult or impossible to conduct meaningful load flow studies for some transmission planning purposes,[1426] and the competitive playing field is tilted toward those who have this information and away from those who do not.[1427]

642. The Commission therefore required in Order No. 890, and we apply that requirement to Long-Term Regional Transmission Planning in this final order, disclosure of the methodology, criteria, assumptions, data and other information that underlie transmission plans, including Long-Term Scenarios. We recognize that no bright line rule exists to determine the appropriate balance between ensuring transparency in the transmission planning processes and ensuring that confidential information is not disclosed inappropriately. Transmission providers may propose what they believe are appropriate confidentiality protections in their filings to comply with this final order, and the Commission will evaluate those proposals by using the established principles in Order No. 890, as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

643. With respect to the issue raised by ELCON and Pine Gate about timely data,[1428] we decline to adopt their suggestion to define precisely what ''timely'' means with respect to best available data because we believe flexibility is warranted given the diverse regional transmission planning processes to which this reform will apply. That is, we believe that updating data inputs may require different timelines depending on the transmission planning region and the specific data input, where each input may change on a different timeline. However, given the five-year duration of the Long-Term Regional Transmission Planning cycle, and the risk of data becoming stale, we require transmission providers to update their data inputs at least once at the outset of each Long-Term Regional Transmission Planning cycle.

644. With respect to National Grid's request to clarify the definition of ''diverse'' in the context of the requirement that data inputs must be developed using diverse and expert perspectives,[1429] we clarify that the term ''diverse'' specifically used in the context of data inputs indicates that the data inputs must represent a range of data within the bounds of plausibility. We believe that this requirement will ensure that the *set* of Long-Term Scenarios that are developed from these data inputs will represent a reasonable range of probable future outcomes consistent with the requirement for plausibility.

8. Identification of Geographic Zones

a. NOPR Proposal

645. In the NOPR, the Commission proposed to require that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. If transmission providers within a transmission planning region choose to establish geographic zones, then the Commission proposed to require the transmission provider to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.[1430]

646. The Commission preliminarily found that requiring the consideration and potential identification of geographic zones within Long-Term Scenarios assists transmission providers, transmission developers, and generation developers in coordinating their activities. The Commission stated that transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest. Further, the Commission stated that, using the information gained through the process described below to identify such geographic zones, transmission providers in each transmission planning region could then plan transmission facilities that would serve large concentrations of new generation in a more efficient or cost-effective manner.[1431]

647. The Commission proposed to require, as step one of the three-step geographic zone process, that transmission providers consider

[1422] PJM Reply Comments at 22.

[1423] *See supra* Number and Development of Long-Term Scenarios section.

[1424] *Sw. Power Pool, Inc.,* 137 FERC ¶ 61,227 at P 20.

[1425] Order No. 890, 118 FERC ¶ 61,119 at P 471.

[1426] *Id.* P 478.

[1427] *Sw. Power Pool, Inc.,* 137 FERC ¶ 61,227 at P 20.

[1428] ELCON Initial Comments at 13; Pine Gate Initial Comments at 28–29.

[1429] National Grid Initial Comments at 14.

[1430] NOPR, 179 FERC ¶ 61,028 at P 145.

[1431] *Id.* P 146.

whether to establish and include in the regional transmission planning process outlined in their OATTs the method that they will use to identify geographic zones within the transmission planning region. The Commission also proposed to require that transmission providers in each transmission planning region use this information to create a set of draft geographic zones, and that they post on their OASIS or other public website maps of the draft geographic zones, as well as the information used to create the draft geographic zones, for stakeholders' input.[1432]

648. In addition, the Commission proposed to require transmission providers in each transmission planning region to consider this stakeholder feedback and modify the draft geographic zones as appropriate to produce a final list of designated geographic zones within the transmission planning region.[1433]

649. The Commission proposed to require, in step two of the three-step geographic zone process, that transmission providers in each transmission planning region assess generation developers' commercial interest in developing generation within each designated geographic zone.[1434] The Commission proposed to require, in the final step of the three-step geographic zone process, that transmission providers in each transmission planning region incorporate the information from step one and step two regarding the designated geographic zones into their Long-Term Scenarios.[1435]

b. Comments

650. Many commenters support the Commission's proposal to require each transmission provider, as part of its regional transmission planning process, to consider whether to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.[1436] Commenters assert that, compared to interconnection-related network upgrades identified on a case-by-case basis in the interconnection process, identifying and incorporating geographic zones into Long-Term Scenarios would save consumers money by identifying more efficient or cost-effective transmission facilities to connect areas with the potential for low cost generation to load centers and reduce congestion and generator curtailment.[1437] Further, commenters note the success of previous planning efforts in ERCOT, MISO, CAISO, and ISO–NE to incorporate geographic zones into their transmission planning efforts.[1438]

651. Some commenters highlight the importance of this proposed reform for remotely located renewable resources generally, and more specifically for offshore wind, which is constrained to lease areas auctioned by the Bureau of Ocean Energy Management.[1439] For example, Ørsted argues that the location and approximate resource potential of offshore wind is well understood and the failure to proactively plan the necessary transmission would result in higher costs to ratepayers.[1440] BP further contends that the geographic zones in which National Interest Electric Transmission Corridors are likely to be established also merit inclusion in transmission planning.[1441]

652. Some commenters support the proposal but urge the Commission to *require* the identification of geographic zones and planning transmission to integrate generation in those zones rather than just requiring transmission providers to *consider* whether to identify geographic zones.[1442] Acadia Center and CLF argue that the Commission should require the identification and creation of geographic zones in areas where the majority of states have binding greenhouse gas emission reduction or renewables mandates, which could result in fewer transmission corridors being built, thereby reducing costs, siting challenges, and benthic environmental impacts.[1443] Acadia Center and CLF assert that, without mandatory identification and establishment of geographic zones, there is a significant risk that adequate transmission will not be built to accommodate state emission reduction and renewables mandates in a cost-effective or efficient way.[1444]

653. In contrast, other commenters emphasize that they support the proposal to require transmission providers to *consider* identifying geographic zones rather than to actually identify such geographic zones.[1445] Such commenters assert that providing the option to identify geographic zones would allow transmission providers to determine, with their stakeholders, what is right for their transmission planning region.[1446]

654. Other commenters express concerns with the idea of incorporating geographic zones with the potential for large amounts of generation into regional transmission planning, but do not oppose the proposal so long as it is optional.[1447] For example, NESCOE and

[1432] *Id.* PP 147–148.

[1433] The Commission noted that, while it referred to multiple ''zones,'' subsequent to stakeholder feedback, the final list may contain only one designated geographic zone. *Id.* P 149.

[1434] *Id.* P 150.

[1435] *Id.* P 151.

[1436] Ameren Initial Comments at 15; American Municipal Power Initial Comments at 35; Clean Energy Associations Initial Comments at 13; EEI Initial Comments at 15; ENGIE Initial Comments at 4; Eversource Initial Comments at 21–22; Interwest Reply Comments at 4; ISO–NE Initial Comments at 30; ITC Initial Comments at 5, 13–17; Middle River Power Initial Comments at 3; MISO Initial Comments at 30; NARUC Initial Comments at 16; Nebraska Commission Initial Comments at 6–7; NESCOE Initial Comments at 37; New Jersey Commission Initial Comments at 15; New York TOs Initial Comments at 12; New York Transco Initial Comments at 5–6; Northwest and Intermountain Initial Comments at 5–6; NRECA Initial Comments at 37; New York Commission and NYSERDA Initial Comments at 14–15; NYISO Initial Comments at 29–30; Ørsted Initial Comments at 7; US DOE Initial Comments at 18; Western PIOs Initial Comments at 31–32.

[1437] *See, e.g.,* ENGIE Initial Comments at 4; Eversource Initial Comments at 21–22; ITC Initial Comments at 13–17; Northwest and Intermountain Initial Comments at 5–6; NYISO Initial Comments at 29–30.

[1438] *See, e.g.,* ENGIE Initial Comments at 4; Eversource Initial Comments at 21–22.

[1439] *See, e.g.,* BP Initial Comments at 4, 7–8; Clean Energy Buyers Initial Comments at 18; New York Transco Initial Comments at 5–6; Ørsted Initial Comments at 7–8.

[1440] *See, e.g.,* Ørsted Initial Comments at 7–8.

[1441] BP Initial Comments at 7 (citing 16 U.S.C. 824p).

[1442] Acadia Center and CLF Initial Comments at 13–15; Amazon Initial Comments at 6–7; California Water Initial Comments at 16; Center for Biological Diversity Initial Comments at 13–15; City of New York Initial Comments at 7–8; Handy Law Initial Comments at 12; Invenergy Reply Comments at 9–10; SEIA Initial Comments at 11–12; Shell Initial Comments at 23.

[1443] Acadia Center and CLF Initial Comments at 13–14.

[1444] *Id.* at 13.

[1445] *See, e.g.,* Ameren Initial Comments at 15–16; American Municipal Power Initial Comments at 34–35; Clean Energy Associations Initial Comments at 13; EEI Initial Comments at 15; ISO–NE Initial Comments at 30; ITC Initial Comments at 5, 13–17; MISO Initial Comments at 30; Nebraska Commission Initial Comments at 6–7; NESCOE Initial Comments at 37; NRECA Initial Comments at 37; New York Commission and NYSERDA Initial Comments at 14–15; NYISO Initial Comments at 32; PPL Initial Comments at 11; US Chamber of Commerce Initial Comments at 7.

[1446] *See, e.g.,* EEI Initial Comments at 15; ISO–NE Initial Comments at 30; MISO Initial Comments at 30; New York Commission and NYSERDA Initial Comments at 14–15; NYISO Initial Comments at 32.

[1447] APPA Initial Comments at 29–30; Dominion Initial Comments at 28–29; Georgia Commission Initial Comments at 6; Large Public Power Initial Comments at 22; National Grid Initial Comments at 16–17; NESCOE Initial Comments at 38; SERTP Sponsors Initial Comments at 27; SPP Market Monitor Initial Comments at 11–12; TANC Initial Comments at 10.

National Grid assert that the proposed requirements for each of the three steps is overly prescriptive and could be included in a final order as guidance, but not as a mandate.[1448]

655. Several commenters urge the Commission to provide flexibility in any process for considering and potentially identifying geographic zones.[1449] For example, Michigan Commission states that the proposed three-step process in the NOPR is highly prescriptive and overly burdensome, and instead the Commission should provide greater flexibility to ensure that generation siting assumptions included in Long-Term Scenarios are developed transparently in collaboration with state regulators, generation utilities, and resource planners.[1450]

656. Several commenters suggest modifications to the NOPR proposal.[1451] For example, Vistra contends that the NOPR proposal could be improved through the use of open seasons or other comparable tools to elicit concrete commitments from generator developers.[1452] Other commenters argue that the NOPR proposal should be modified to involve a subscription model in which prospective generation resources within the zone indicate their willingness to pay for transmission to the zone.[1453] Although PJM opposes the NOPR proposal, PJM argues that these alternative proposals offered by Vistra and New Jersey Commission have merit and are worthy of further dialogue.[1454]

657. Regarding the specific steps in the NOPR proposal for identifying geographic zones, several commenters support the proposal to provide all stakeholders, including relevant Federal and state siting authorities, with a meaningful opportunity to provide input on the draft geographic zones.[1455] Other commenters, however, assert that the Commission should provide a clearer role for states and other stakeholders to participate earlier in the process of identifying geographic zones.[1456]

658. Some commenters argue that the NOPR proposal regarding what information transmission providers should use to gauge commercial interest in geographic zones is overly prescriptive and that the information would be too speculative to be an accurate indicator of commercial interest.[1457] Several commenters urge the Commission to increase the transparency of the NOPR proposal.[1458] For example, US DOE recommends that the Commission specify minimum standards for reporting the attributes of each geographic zone.[1459]

659. Several commenters oppose the proposal to require transmission providers to consider whether to identify geographic zones with the potential for large amounts of generation.[1460] For example, APS argues that the proposal may not be appropriate due to the speculative nature of the identification of geographic zones and the long-term nature of planning and building transmission infrastructure.[1461] Idaho Power is concerned that the NOPR proposal will create a significant level of work for transmission providers that would outweigh the minor benefits developers would receive from the data.[1462]

660. PJM opposes the NOPR proposal, which it describes as an arbitrary and inflexible process that fails to account for regional differences and that will require transmission providers to draw lines on a map and commit to these areas for 20 years.[1463] PJM states that the information from the geographic zones will be poor compared to information in the marketplace, including nearer term decisions of interconnection customers.[1464] PJM states that an alternative, more case-specific flexible approach that builds on and is better synchronized with the transmission provider's interconnection queue process and market developments, and accommodates topologies as diverse as those in PJM, is a better solution.[1465] For example, PJM suggests that the PJM State Agreement Approach is a better way to facilitate clusters of renewable energy interconnections by finding states that are willing to sponsor the new transmission to help fulfill a renewable energy policy.[1466]

661. Several state commissions express concerns that the NOPR proposal would give undue preference to certain kinds of resources.[1467] For example, North Dakota Commission argues that the NOPR proposal would bias transmission planning towards one type of generation, encourage speculative build-out of transmission, and prevent visibility into the cost of other generation/transmission combinations, which will result in under-utilized transmission and additional costs to ratepayers with little benefit.[1468]

662. North Carolina Commission and Staff assert that the NOPR proposal is an unwarranted intrusion into state jurisdiction over generation and fails to acknowledge state authority over utility generation, resource portfolios, and

[1448] NESCOE Initial Comments at 38; National Grid Initial Comments at 16.

[1449] *See, e.g.,* APS Initial Comments at 5; ISO–NE Initial Comments at 30; Michigan Commission Initial Comments at 6; MISO Initial Comments at 42; MISO TOs Initial Comments at 32; NARUC Initial Comments at 17; New Jersey Commission Initial Comments at 15; NYISO Initial Comments at 3–4.

[1450] Michigan Commission Initial Comments at 6.

[1451] Acadia Center and CLF Initial Comments at 15–16; California Energy Commission Initial Comments at 2–3; Center for Biological Diversity Initial Comments at 13–16; Clean Energy Associations Initial Comments at 24–25; Illinois Commission Initial Comments at 9–11; Large Public Power Initial Comments at 26; Microgrid Resources Coalition Initial Comments at 4–6; New Jersey Commission Initial Comments at 16–17; Vistra Initial Comments at 24.

[1452] Vistra Initial Comments at 24.

[1453] Clean Energy Associations Initial Comments at 24–25; Large Public Power Initial Comments at 26; New Jersey Commission Initial Comments at 16–17.

[1454] PJM Reply Comments at 29–30, 31–32.

[1455] ISO/RTO Council Initial Comments at 8; NARUC Initial Comments at 16–17; National Grid Initial Comments at 17; Nebraska Commission Initial Comments at 7; SEIA Initial Comments at 12–13; Shell Initial Comments at 25.

[1456] Acadia Center and CLF Initial Comments at 12–13; AEE Initial Comments at 24–25; Amazon Initial Comments at 7; CAISO Initial Comments at 4–5, 28–29, 31; DC and MD Offices of People's Counsel Initial Comments at 15–16; Interwest Initial Comments at 9; ISO–NE Initial Comments at 29; National Grid Initial Comments at 17–18; NESCOE Initial Comments at 38–39; Nevada Commission Initial Comments at 9–10; SERTP Sponsors Initial Comments at 27.

[1457] *See, e.g.,* Middle River Power Initial Comments at 3; MISO Initial Comments at 43; PJM Initial Comments at 84.

[1458] Amazon Initial Comments at 8; Shell Initial Comments at 23–24; US DOE Initial Comments at 24–25

[1459] US DOE Initial Comments at 20.

[1460] APS Initial Comments at 5–7; Arizona Commission Initial Comments at 8; CAISO Initial Comments at 27–28; Consumer Organizations Initial Comments at 3–7; Duke Initial Comments at 4, 18–19; Idaho Power Initial Comments at 5; Indicated PJM TOs Initial Comments at 3–4, 12–13; ISO/RTO Council Initial Comments at 7; LADWP Initial Comments at 4; Louisiana Commission Initial Comments at 24–25; Michigan Commission Initial Comments at 5–6; Microgrid Resources Initial Comments at 5; North Carolina Commission and Staff Initial Comments at 8–10; North Dakota Commission Initial Comments at 4–5; Ohio Commission Federal Advocate Initial Comments at 7–8.

[1461] APS Initial Comments at 6–7.

[1462] Idaho Power Initial Comments at 5.

[1463] PJM Initial Comments at 77–78.

[1464] *Id.* at 77.

[1465] *Id.* at 7.

[1466] *Id.* at 79–82 (citing PJM Operating Agreement, Schedule 6, section 1.5.9).

[1467] Arizona Commission Initial Comments at 8; Louisiana Commission Initial Comments at 24–25; Louisiana Commission Reply Comments at 11–12; Michigan Commission Initial Comments at 5–6; North Carolina Commission and Staff Initial Comments at 10–13; North Dakota Commission Initial Comments at 4; Ohio Commission Federal Advocate Initial Comments at 7–8; Pennsylvania Commission Initial Comments at 7–8.

[1468] North Dakota Commission Initial Comments at 4.

integrated resource planning.[1469] Similarly, Ohio Commission Federal Advocate asserts that the NOPR proposal exceeds the Commission's authority and interferes with Ohio's ability to maintain its competitive retail electric service law.[1470] Mississippi Commission states that decisions to develop such zones within a state should be left to the state.[1471] Pennsylvania Commission argues that the geographic zones used for Long-Term Scenarios could frustrate a state's legitimate policy choices in establishing, for example, economic development zones designed to encourage developers to site generation in specific areas, by favoring another state's policy choices.[1472] TAPS opposes any requirement to undertake a process to consider and identify remote geographic zones where state or local laws require local generating resources rather than remote resources.[1473]

663. Many commenters argue that the NOPR proposal would be duplicative of, or would interfere with, existing processes.[1474] AEE states that the consideration of geography in developing long-term regional transmission plans should occur as a natural outgrowth of more effective regional transmission planning and that a specific requirement to identify geographic zones could have unintended consequences.[1475] AEE further asserts that some of the factors that the NOPR proposes to require transmission providers to incorporate in their Long-Term Scenarios inherently require them to consider what geographic areas are ripe for low-cost generation development but are isolated or otherwise transmission constrained.[1476] Similarly, Indicated PJM TOs argue that it is unnecessary to require the identification of geographic zones in Long-Term Regional Transmission Planning because transmission providers necessarily will rely on driving factors (*e.g.,* public policy goals) that will determine where renewable resources will be developed.[1477] According to Duke, the categories of factors proposed in the NOPR already capture generator interconnections, so it is unclear what this additional process will add.[1478]

664. Several commenters argue that some transmission planning processes already incorporate the identification of geographic zones, and those existing processes should be allowed to continue.[1479] ISO–NE claims that transmission providers' planning constructs may already include rules that allow for assessing and identifying geographic zones with potential for high renewable development, rendering a separate process redundant or unnecessary.[1480] SPP states that the NOPR proposal would duplicate SPP's current process to some extent and that it would not be practical to do both.[1481] Similarly, CAISO argues that the NOPR proposal is overly prescriptive and would interfere with California's existing processes, which are working effectively.[1482] New York TOs note that New York's transmission planning processes already include the evaluation of geographic zones expected to see significant growth in generation or changes in load and incorporate state involvement.[1483] Mississippi Commission asserts that MISO already considers geographic zones for new generation.[1484]

c. Commission Determination

665. We decline to adopt the proposed requirement that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. We are persuaded by commenters that finalizing and requiring the NOPR proposal is not warranted at this time. Further, given the other requirements in this final order, such as the requirement for transmission providers to plan for factors affecting supply and demand, we agree with commenters that adopting this proposed requirement is not necessary at this time to ensure that Long-Term Regional Transmission Planning ensures just and reasonable rates. We also agree with commenters that the prescriptive nature of the proposed three-step process could unintentionally impede existing efforts to incorporate geographic zones into regional transmission planning.

666. Although we are not adopting the NOPR proposal, we encourage transmission providers to consider geographic zones that have the potential for development of large amounts of new generation as part of their regional transmission planning process. As such, transmission providers in a transmission planning region may propose to identify geographic zones as part of Long-Term Regional Transmission Planning on compliance with this final order, provided that they demonstrate that their process for identifying such geographic zones is consistent with or superior to the Long-Term Regional Transmission Planning requirements established herein.

D. Evaluation of the Benefits of Regional Transmission Facilities

667. In this final order, we require transmission providers, as part of Long-Term Regional Transmission Planning, to measure seven specified benefits that were enumerated in the NOPR (''set of seven required benefits'' or ''required benefits'') in each Long-Term Scenario. We also allow transmission providers to propose on compliance to measure additional benefits as part of Long-Term Regional Transmission Planning. In addition, we require transmission providers to use those measured benefits when evaluating Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs.[1485]

668. This section of the final order discusses the requirements that we adopt governing transmission providers' measurement and use of benefits in Long-Term Regional Transmission Planning. Specifically, we discuss: (1) the requirement to use a set of seven required benefits; (2) the required benefits, themselves; (3) the requirement

[1469] North Carolina Commission and Staff Initial Comments at 8.

[1470] Ohio Commission Federal Advocate Initial Comments at 7 (quoting Ohio Commission Federal Advocate ANOPR Comments at 8).

[1471] Mississippi Commission Reply Comments at 10.

[1472] Pennsylvania Commission Initial Comments at 7–8.

[1473] TAPS Initial Comments 9–10.

[1474] AEE Initial Comments at 8; APS Initial Comments at 5; CAISO Initial Comments at 4–5; Duke Initial Comments at 18–19; Illinois Commission Initial Comments at 9–11; Indicated PJM TOs Initial Comments at 12; ISO–NE Initial Comments at 30; ISO/RTO Council Initial Comments at 7; MISO TOs Initial Comments at 32; Mississippi Commission Reply Comments at 10; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12–13; TAPS Initial Comments 8–10; Xcel Initial Comments at 10–11.

[1475] AEE Initial Comments at 8.

[1476] *Id.* at 23–24.

[1477] Indicated PJM TOs Initial Comments at 12.

[1478] Duke Initial Comments at 18.

[1479] *See, e.g.,* CAISO Initial Comments at 27–33; ISO–NE Initial Comments at 30; MISO TOs Initial Comments at 32; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12–13.

[1480] ISO–NE Initial Comments at 30.

[1481] SPP Initial Comments at 12–13.

[1482] CAISO Initial Comments at 4–5, 27–33.

[1483] New York TOs Initial Comments at 12.

[1484] Mississippi Commission Reply Comments at 10.

[1485] As discussed in the Development of Long-Term Scenarios section *supra,* transmission providers must also use these benefits to inform their identification of Long-Term Transmission Needs.

to include a general description of how transmission providers will measure each of the benefits that the final order requires, as well as any additional benefits that they may propose, in their OATTs; (4) the requirements related to the minimum time horizon over which transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities; (5) the evaluation of the benefits of portfolios of Long-Term Regional Transmission Facilities; and (6) other issues related to benefits.

1. Requirement for Transmission Providers To Use a Set of Seven Required Benefits

a. NOPR Proposal

669. In the NOPR, the Commission proposed a list of benefits that transmission providers in each transmission planning region may consider in Long-Term Regional Transmission Planning and cost allocation processes, which included: (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.[1486] The NOPR provided a description of each of these benefits categories as well as a method to calculate benefits in each category.[1487]

670. The Commission explained that it was not proposing to make the list of potential benefits mandatory or exhaustive and that transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.[1488]

671. The 12 potential benefits described in the NOPR are:

Number	Benefit	Description
1	Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement.	Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.
2a	Reduced loss of load probability [OR next benefit].	Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load.
2b	Reduced planning reserve margin [OR prior benefit].	While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements.
3	Production cost savings	Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also, reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings.
4	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand.
5	Reduced congestion due to transmission outages.	Reduced production costs during transmission outages that significantly increase transmission congestion.
6	Mitigation of extreme events and system contingencies.	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system.
7	Mitigation of weather and load uncertainty.	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.
8	Capacity cost benefits from reduced peak energy losses.	Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses.
9	Deferred generation capacity investments.	Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas.
10	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources).
11	Increased competition	Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power.
12	Increased market liquidity	Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for Long-Term Regional Transmission Planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion.

[1486] NOPR, 179 FERC ¶ 61,028 at P 185. As more fully described below, the Commission is making modifications to the list of benefits in this final order. Therefore, we clarify for the reader how we refer to each of those benefits in this section. We refer to benefits 1–6 as ''Benefit 1,'' ''Benefit 2,'' etc. We refer to Benefit 7, ''mitigation of weather and load uncertainty'' as NOPR Benefit 7. We refer to ''(8) capacity cost benefits from reduced peak energy losses'' as ''NOPR Benefit 8'', ''Final Order Benefit 7'', and ''Benefit 7''. We refer to benefits 9–12 as ''Benefit 9,'' Benefit 10,'' etc.

[1487] *Id.* PP 189–225.

[1488] *Id.* P 184.

672. While the Commission did not propose to require use of any specific benefits in the NOPR, it sought comment on whether transmission providers should be required to use some or all of the potential benefits described in the NOPR as a minimum set of benefits for their Long-Term Regional Transmission Planning process.[1489]

b. Comments

673. Many commenters support the NOPR approach of providing illustrative benefits rather than mandating the use of certain benefits.[1490] Indicated PJM TOs contend that the NOPR proposal would advance the Commission's goals better than a more prescriptive proposal.[1491] SERTP Sponsors and Southern argue that the Commission should not impose a minimum set of benefits because existing state-regulated integrated resource planning processes adequately examine some of the proposed benefits, and that some of the proposed benefits would harm existing integrated resource planning processes or are only appropriate for RTO/ISO regions.[1492] LADWP asserts that some or all of the identified benefits will be considered as part of the normal transmission planning process without a requirement.[1493] Dominion asserts that the question arises of who will judge whether a transmission project addresses the NOPR's proposed list of benefits and that such debates could be time-consuming and further delay projects and drive up costs.[1494] Dominion states that transmission providers should be permitted to identify the benefits that they will consider in conducting Long-Term Regional Transmission Planning but retain flexibility to apply the specific benefits that are most appropriate given each transmission provider's individual circumstances.[1495]

674. TAPS supports requiring transmission providers to evaluate production cost modeling but opposes requiring transmission providers to consider any other benefits in order to allow for regional flexibility.[1496] Northwest and Intermountain and NYISO ask that the final order confirm that the 12 illustrative benefits are neither mandatory nor exhaustive.[1497] California Municipal Utilities state that requiring the consideration of all 12 benefits proposed in the NOPR would misapprehend the state and local nature of resource portfolio planning and fail to account for the costs of such prescriptive measures and the need for consumer protection measures to guard against speculative transmission projects.[1498]

675. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.[1499] Relatedly, Xcel states that for any specific study, portfolio, or transmission project, all benefits do not need to be calculated and, in some cases, calculating additional benefits may be costly, time consuming, and contentious and provide little added value.[1500]

676. Many of the commenters that support an illustrative approach emphasize the importance of regional flexibility.[1501] US Chamber of Commerce states that flexibility will allow transmission planning regions to consider benefits that best align with their respective market structures.[1502] MISO states that, without flexibility, it may not be able to move forward with the transmission projects of the greatest benefit and value to MISO and its stakeholders, noting that benefits used to meet criteria for its recent Long-Range Transmission Planning projects are not specified in its OATT.[1503] MISO, NYISO, and SPP argue that transmission providers and their stakeholders ought to determine what the benefits evaluated for specific transmission projects or sets of projects should be.[1504] NARUC, New York TOs, and Pennsylvania Commission agree, emphasizing consultation with states.[1505]

677. Entergy urges the Commission to affirm its commitment to providing transmission planning regions with flexibility in terms of how they identify, consider, and calculate benefits. Entergy further urges the Commission to adopt guiding principles to aid transmission providers in identifying their own benefits.[1506] Entergy argues that the Commission should recognize that not all benefits are appropriate in all jurisdictions and that some states will want to prioritize transmission projects that reduce customer bills.[1507]

678. SPP argues that how and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each transmission provider and its stakeholders. Specifically, SPP argues that the effort required to incorporate additional benefit metrics into its current transmission planning process cannot be accommodated within its current process timeline.[1508]

679. Mississippi Commission argues that any required benefits would be arbitrary and some metrics may not be applicable at times.[1509] National Grid

[1489] *Id.* P 188.

[1490] Ameren Initial Comments at 19; APPA Initial Comments at 31; APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22–23; EEI Initial Comments at 19–20; Eversource Initial Comments at 25; Georgia Commission Initial Comments at 6–7; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7–8; Illinois Commission Initial Comments at 13–14; Indiana Commission Initial Comments at 6; Indicated PJM TOs Initial Comments at 17; ISO–NE Initial Comments at 5, 33–34; LADWP Initial Comments at 5; Louisiana Commission Reply Comments at 9–10; Michigan Commission Initial Comments at 6; MISO Initial Comments at 9, 51–52; Mississippi Commission Initial Comments at 36; NARUC Initial Comments at 20–21; National Grid Initial Comments at 26; North Carolina Commission and Staff Initial Comments at 7; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; NRECA Initial Comments at 43–45; NYISO Initial Comments at 9, 37–38; OMS Initial Comments at 7–8; Pacific Northwest Utilities Initial Comments at 8; Pennsylvania Commission Initial Comments at 9; SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 24; TANC Initial Comments at 16; TAPS Initial Comments at 3, 14; US Chamber of Commerce Initial Comments at 7; Vermont State Entities Initial Comments at 7; Virginia Commission Staff Initial Comments at 5; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

[1491] Indicated PJM TOs Initial Comments at 17.

[1492] SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 25–27.

[1493] LADWP Initial Comments at 5.

[1494] Dominion Initial Comments at 34.

[1495] *Id.*

[1496] TAPS Initial Comments at 3, 14.

[1497] Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

[1498] California Municipal Utilities Reply Comments at 5–6.

[1499] OMS Initial Comments at 8.

[1500] Xcel Initial Comments at 12.

[1501] Ameren Reply Comments at 16–17 (citing MISO Initial Comments at 9); APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22–23; EEI Initial Comments at 19–20; Eversource Initial Comments at 25; Entergy Reply Comments at 3; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7–8; Illinois Commission Initial Comments at 13–14; Indiana Commission Initial Comments at 6–7; Large Public Power Initial Comments at 28; ISO–NE Initial Comments at 33–34; Massachusetts Attorney General Initial Comments at 12, 15; MISO Initial Comments at 9; Mississippi Commission Initial Comments at 35–36; NARUC Initial Comments at 20–21; National Grid Initial Comments at 26; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9; SPP Initial Comments at 18; US Chamber of Commerce Initial Comments at 7; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

[1502] US Chamber of Commerce Initial Comments at 7.

[1503] MISO Initial Comments at 9.

[1504] MISO Initial Comments at 9–10; NYISO Initial Comments at 39; SPP Initial Comments at 18.

[1505] NARUC Initial Comments at 21–22; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9.

[1506] Entergy Initial Comments at 21.

[1507] *Id.*

[1508] SPP Initial Comments at 18.

[1509] Mississippi Commission Initial Comments at 35–36.

argues that flexibility will allow transmission providers to adapt more readily to changes in state policy drivers, prevent the requirements of Long-Term Regional Transmission Planning from becoming dated, and allow benefits and cost allocation discussions to be synchronized.[1510] Duke contends that allowing regional flexibility may help to mitigate some disputes within transmission planning regions over what benefits to measure and how to measure them. Moreover, Duke argues that regional flexibility is critical to ensuring that each benefit metric used is relevant and calculable for each transmission planning region, particularly given differences between RTO/ISO and non-RTO/ISO regions. Duke contends that regions must not be forced into accepting and implementing benefits metrics that they have not vetted or on which they do not have consensus.[1511]

680. MISO, while stating its preference for flexibility in identifying benefits, also states that it would support identifying and using a general set of benefit metrics that capture key areas of transmission value, such as reliability and resilience, production cost savings, and avoided resource and/or transmission investment, assuming that each transmission planning region may determine how to calculate each metric and how each applies during a transmission assessment, as well as allowing for different benefit metrics not part of that ''general set'' to be applied when warranted.[1512]

681. Some commenters offer support for the illustrative benefits without suggesting that they be required.[1513] PG&E states that CAISO's transmission planning process currently evaluates several of the same benefits, either routinely or on a case-specific basis, and that PG&E supports the continued flexibility the NOPR envisions for RTO/ISOs.[1514]

682. In contrast, many commenters support the Commission requiring that transmission providers consider a minimum list of benefits for Long-Term Regional Transmission Planning.[1515] PIOs argue that most of the benefits outlined in the NOPR have broad support, even among those commenters that do not support a Commission requirement to consider a minimum set of benefits.[1516]

683. Clean Energy Associations and US Senator Schumer assert that the failure to adopt a minimum list of benefits risks skewing benefit-to-cost ratios against developing necessary transmission because all costs would be included in an evaluation but not all benefits would also be included.[1517] Clean Energy Associations further state that failing to require the adoption of a minimum list of benefits could lead to higher costs in the long-term, as larger transmission projects with net benefits would not be selected.[1518] Finally, Clean Energy Associations argue that, without a minimum list of benefits, significant disparities in regional identification of potential Long-Term Regional Transmission Facilities could have harmful spillover effects on coordinated activities such as interregional transmission coordination and affected systems studies.[1519]

684. Michigan State Entities argue that there must be some prescribed list of benefits, asserting that it would not force differently situated transmission providers to implement any specific policy, but instead would ensure that they take a ''fair look'' at transmission planning policies, including those using storage, that could produce substantial savings for customers.[1520] Interwest contends that a standard and comprehensive framework for evaluating benefits is necessary because an ad hoc approach could result in inconsistencies and an incomplete picture of a transmission project's potential benefits.[1521]

685. Southeast PIOs urge the Commission to prescribe a set of benefits for use in benefit-cost analyses, starting with the entire list of benefits in the NOPR. Southeast PIOs argue that the transmission providers in the Southeast exploited the flexibility in establishing and assessing benefits that the Commission provided in Order No. 1000 to implement a straight cost comparison.[1522] Southeast PIOs further state that minimum standards are necessary to produce actionable results; otherwise, Long-Term Regional Transmission Planning will devolve into a ''box-checking exercise.'' [1523] SREA argues that the Commission needs to set clear guidelines around benefit metrics to avoid opponents to the NOPR finding easy work-arounds.[1524]

686. Similarly, R Street states that transmission providers should be required to use a minimum set of benefits because they lack the incentive to account for all system-wide benefits. R Street argues that proposing a benefits list for transmission providers to consider is the status quo and the Commission should expect little change without a benefits requirement.[1525] Concerned Scientists agree, claiming that the experience with Order No. 1000 implementation and the descriptions in the comments in response to the NOPR illustrate how transmission planning processes are resistant to changes when the Commission provides latitude for discretion.[1526] Concerned Scientists further contend that the discretion provided in the NOPR will allow a pattern of undue discrimination and unjust and unreasonable rates to persist

[1510] National Grid Initial Comments at 26–27.

[1511] Duke Initial Comments at 22–23.

[1512] MISO Initial Comments at 9.

[1513] Nevada Commission Initial Comments at 10–11; Pattern Energy Initial Comments at 14; PG&E Initial Comments at 7.

[1514] PG&E Initial Comments at 7.

[1515] ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at 6, 23–25; Breakthrough Energy Initial Comments at 4, 21–22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11–12; Clean Energy Buyers Reply Comments at 8–9; Concerned Scientists Reply Comments at 7–10; Cypress Creek Reply Comments at 7–8; DC and MD Offices of People's Counsels Reply Comments at 3, 7–8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16: Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18–22; Interwest Initial Comments at 12; Interwest Reply Comments at 6–7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11–14; Pacific Northwest State Agencies Initial Comments at 16–17; PIOs Initial Comments at 27–28; PIOs Reply Comments at 7–8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16–17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; US DOE Initial Comments at 30–33; US Senator Schumer Supplemental Comments at 1–2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

[1516] PIOs Initial Comments at 26, 41; PIOs Reply Comments at 7–8.

[1517] Clean Energy Associations Initial Comments at 19; US Senator Schumer Supplemental Comments at 1–2.

[1518] Clean Energy Associations Initial Comments at 19–20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses,* at 26 (Apr. 2021)).

[1519] Clean Energy Associations Initial Comments at 19.

[1520] Michigan State Entities Reply Comments at 2.

[1521] Interwest Reply Comments at 7.

[1522] Southeast PIOs Initial Comments at 50.

[1523] Southeast PIOs Reply Comments at 23, 27.

[1524] SREA Reply Comments at 26 (citing Louisiana Commission Initial Comments at 17; Mississippi Commission Initial Comments at 11; Southern Initial Comments at 12).

[1525] R Street Initial Comments at 9.

[1526] Concerned Scientists Reply Comments at 7.

that initially motivated the Commission to act.[1527]

687. Some commenters assert that requiring the same benefits in different transmission planning regions will help increase interregional transmission coordination.[1528] Clean Energy Associations argue that it is important for transmission planning regions to have a common starting point in terms of which benefits they evaluate to facilitate greater interregional transmission coordination.[1529] Breakthrough Energy notes that load diversity—and its effect on reducing very expensive generation capacity costs—is a major and under-appreciated benefit of large-scale interregional transmission facilities.[1530] Grid United states that, without a minimum set of benefits criteria, disparate benefits in neighboring transmission planning regions could balkanize the grid and disrupt effective interregional transmission planning, emphasizing the need for a set of principles that outline benefits that are universal and necessary for effective long-term transmission planning.[1531] Policy Integrity asserts that defining a uniform set of minimum benefits would facilitate better identification and selection of efficient and cost-effective transmission solutions and would ensure comparability of transmission expansion projects across different RTOs/ISOs, which will be particularly useful given the need to improve Interregional Transfer Capability.[1532]

688. Relatedly, PJM states that, while it agrees that transmission providers should have flexibility to propose which benefits make sense to consider for their own transmission planning regions, the Commission should adopt a core set of benefits to be considered nationwide to ensure consistency.[1533] SREA notes that, in RTOs/ISOs, seams are perpetually a problem due to a lack of common national standards on benefits metrics and data inputs and asserts that the Commission should set minimum standards.[1534]

689. Some commenters assert that a failure to consider sufficient benefits could result in higher costs and/or unjust and unreasonable rates.[1535] According to Enel, without considering a larger number of benefits, transmission projects that would have large net benefits will not be selected if no benefits or even only a small number of potential benefits were compared against the upfront costs.[1536]

690. Some commenters assert that a failure to require consideration of specific benefits will undermine other aspects of the NOPR's proposed reforms.[1537] Anbaric, for instance, argues that the NOPR falls far short of requiring comprehensive transmission planning, because it does not propose to mandate the use of any specific set of benefits.[1538] RMI contends that there is overwhelming evidence that transmission infrastructure provides multiple, diverse benefits, as well as established precedent that transmission costs should be allocated roughly commensurate with benefits. Therefore, RMI states, it would be illogical to allow transmission providers to ignore any benefits that transmission infrastructure offers, as it would lead to flawed investment decisions and defective cost allocation. RMI asserts that transmission providers should be required to quantify the full suite of known benefits of transmission infrastructure in Long-Term Regional Transmission Planning and that the list of 12 benefits in the NOPR is conservative and does not double-count benefits.[1539]

691. AEE argues that several of the listed benefits are indisputably relevant to all transmission planners and that these benefits should form a core group of minimum considerations.[1540] AEE states that the Commission may wish to conduct additional fact-finding in this docket to consider whether additional benefits cut across all markets and transmission planning regions or whether it is necessary to require each region to identify region-specific benefits for inclusion.[1541] Hannon Armstrong states that the Commission indicated that each of the 12 benefits listed in the NOPR has the potential to provide a meaningful contribution to offset the cost of transmission and recommends that, absent any double-counting in this list, the Commission should require each of these benefits to be evaluated.[1542] ITC argues that the Commission should adopt as minimum benefit criteria for project evaluation those used in the recently approved MISO Long-Range Transmission Plan process.[1543]

692. Southeast PIOs claim that the Commission must establish a set of minimum benefits for transmission providers to incorporate in their assessment of regional transmission facilities to ensure that regional transmission facilities are accurately represented in the transmission planning process.[1544] Southeast PIOs contend that a regional transmission planning process that quantifies and fully accounts for benefits of regional transmission alternatives would provide a measure of assurance to regulators and stakeholders that such alternatives were evaluated appropriately.[1545] In response to Southern and SERTP, Southeast PIOs argue that quantifying the listed benefits does not itself make resource decisions; the benefits are meant to determine the value proposition of alternative regional transmission facilities.[1546]

693. GridLab states that the Commission should require transmission providers to justify why their transmission solution evaluation frameworks omit any categories of benefits in relation to a standard list of benefits like those proposed in the NOPR.[1547] Pattern Energy agrees and notes that a ''common starting point'' would lower barriers to entry for market participants that do business in multiple transmission planning regions. Moreover, Pattern Energy argues that a required set of standardized benefits would facilitate a more transparent transmission planning process, as developers would have a baseline knowledge of any single transmission provider's transmission planning

[1527] *Id.* at 8–9.

[1528] Breakthrough Energy Initial Comments at 22–23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27–28; US DOE Initial Comments at 31–32.

[1529] Clean Energy Associations Initial Comments at 19.

[1530] Breakthrough Energy Initial Comments at 22.

[1531] Grid United Initial Comments at 3.

[1532] Policy Integrity Initial Comments at 3, 27–28.

[1533] PJM Initial Comments at 93 (citing NOPR, 179 FERC ¶ 61,028 at P 186).

[1534] SREA Reply Comments at 26–27.

[1535] Enel Initial Comments at 3; Clean Energy Association Initial Comments at 20; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy—Florida Supplemental Comments at 1; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum Supplemental Comments at 1; Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[1536] Enel Initial Comments at 3.

[1537] Anbaric Initial Comments at 6–7; RMI Initial Comments at 2.

[1538] Anbaric Initial Comments at 6–7.

[1539] RMI Initial Comments at 2.

[1540] AEE Initial Comments at 26.

[1541] *Id.*

[1542] Hannon Armstrong Initial Comments at 2–3.

[1543] ITC Initial Comments at 5, 18–22.

[1544] Southeast PIOs Initial Comments at 50.

[1545] *Id.* at 53.

[1546] Southeast PIOs Reply Comments at 28 (citing Southern Initial Comments at 25–26; SERTP Sponsors Initial Comments at 30).

[1547] GridLab Initial Comments at 25.

process regardless of where they are located.[1548]

694. Tabors Caramanis Rudkevich states that when transmission planning analyses account for the benefits of capital cost savings, resource adequacy, and resilience, the total benefits of transmission infrastructure well exceed the cost.[1549] Tabors Caramanis Rudkevich provides an example of multi-value benefit stacking for the transmission line connecting ERCOT and Southern Company and states that the results show total benefits of $390 million, compared to $33 million when considering production cost savings alone.[1550]

695. Certain TDUs and NESCOE support or are amenable to a requirement for minimum benefits that also allows for flexibility in determination of additional benefits.[1551] Specifically, NESCOE recommends that the Commission establish a list of benefits that must be considered for a regional discussion on transmission cost allocation and that the benefits list in the NOPR is an appropriate starting point. However, NESCOE contends, after consulting with the states, transmission providers should have the flexibility to include additional benefits or remove benefits from the list, asserting that such an approach would help facilitate collaboration in determining the appropriate set of benefits for a transmission planning region.[1552] NESCOE also argues that, because benefits and the methods of measuring them may change over time, the Commission should clarify in any final order that transmission providers may modify or add benefits in future FPA section 205 filings.[1553]

696. Certain TDUs also urge the Commission to allow for regional flexibility and state involvement in determining other measurable and quantifiable benefits to use in evaluating Long-Term Regional Transmission Facilities.[1554] While arguing for requiring certain benefits, Cypress Creek states that it agrees with Brattle Group that requiring evaluation of all 12 benefits in every scenario would detract from necessary regional flexibility.[1555] Cypress Creek asserts that the Commission should require two additional project/region-specific benefits in evaluating multi-value projects but does not explain what they should be.[1556]

697. Exelon supports the Commission's proposal to provide flexibility to each transmission planning region to identify which benefits they will use in Long-Term Regional Transmission Planning. For instance, Exelon suggests that congestion reduction is more applicable to regions with Locational Marginal Price pricing, while it may be impossible to calculate the benefits of deferred generation capacity investments in a region like PJM where generation capacity is largely market-driven.[1557] Similarly, the New Jersey Commission recommends providing regional flexibility to include additional benefits that may be harder to quantify and/or do not reduce customers' bills (*e.g.,* resilience benefits and the value of meeting state public policies).[1558]

698. Clean Energy Buyers state that the proposed set of benefits is generally appropriate and that a common set of benefits would allow for the proper identification of benefits in Long-Term Regional Transmission Planning, accounting for changes in the resource mix and demand, and facilitating stakeholder participation. Therefore, Clean Energy Buyers argue, the Commission should require transmission providers to adopt a set of Commission-identified benefits that are consistent with the just and reasonable standard or demonstrate on compliance why they should not have to do so. That said, Clean Energy Buyers state that the Commission should permit transmission providers to propose processes for weighing benefits in accordance with their relative importance in each specific transmission planning region.[1559]

699. Several commenters recognize that benefits analysis can be resource intensive and therefore recommend that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before investing staff resources and modeling work to provide a detailed quantification.[1560] Clean Energy Buyers argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits listed in the NOPR and quantify them accordingly.[1561] Hannon Armstrong states that while certain benefits may have a zero or *de minimis* contribution for certain candidate transmission projects, the Commission should require transmission providers to document each potential benefit by using a high-level screening analysis or detailed modeling as applicable.[1562] PIOs assert that screening tools can be used to reduce analytical burdens, allowing transmission providers to self-certify compliance and/or provide justifications for when benefits do not apply.[1563]

i. List of Benefits Proposed in the NOPR

700. Some commenters support requiring transmission providers to consider all 12 illustrative benefits enumerated in the NOPR.[1564] ACORE contends that these categories represent a best practice and track closely with recommended multi-benefit planning approaches.[1565] Breakthrough Energy notes that some of the Commission-listed benefits can be very significant but are typically ignored in today's transmission planning processes.[1566] SEIA and Fervo assert that the final order should account for the full range of transmission benefits and use multi-value planning to comprehensively identify investments that address all categories of needs and benefits.[1567]

701. PIOs state that there is strong evidence in the record to support the proposed list of benefits, including extensive testimony provided by the Brattle Group and others. PIOs state that these benefits all correlate with needs

[1548] Pattern Energy Reply Comments at 6–8 (citing ACEG Initial Comments at 32; Clean Energy Associations Initial Comments at 21).

[1549] Tabors Caramanis Rudkevich Initial Comments at 6.

[1550] *Id.*

[1551] Certain TDUs Initial Comments at 2–3, 9–12; NESCOE Initial Comments at 43–44.

[1552] NESCOE Initial Comments at 44.

[1553] *Id.* at 43–44.

[1554] Certain TDUs Initial Comments at 9.

[1555] Cypress Creek Reply Comments at 7–8 (citing PIOs Initial Comments Ex. A, ¶¶ 8–9).

[1556] *Id.* at 8.

[1557] Exelon Initial Comments at 15.

[1558] New Jersey Commission Initial Comments at 14.

[1559] Clean Energy Buyers Initial Comments at 19–21.

[1560] ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9; Interwest Initial Comments at 12–13; WATT Coalition Initial Comments at 7.

[1561] Clean Energy Buyers Initial Comments at 20–21.

[1562] Hannon Armstrong Initial Comments at 2–3.

[1563] PIOs Initial Comments at 41.

[1564] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

[1565] ACORE Initial Comments at 12 (citing Rob Gramlich, Grid Strategies LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis,* at 9 (Aug. 9, 2022)).

[1566] Breakthrough Energy Initial Comments at 22.

[1567] Fervo Reply Comments at 2; SEIA Initial Comments at 16.

and goals associated with Long-Term Regional Transmission Planning and, as such, the Commission should require transmission providers to consider them for most, if not all, regional transmission projects. Finally, PIOs encourage the Commission to make clear that these benefits should be assessed as part of any transmission planning process—even those conducted for economic purposes.[1568]

702. Amazon supports the list of benefits set forth in the NOPR and urges the Commission to make consideration of those benefits mandatory except insofar as a transmission provider files for waiver and overcomes a strong presumption of their relevance to transmission planning and cost allocation.[1569] To facilitate the responsible construction of transmission facilities, ENGIE recommends that the Commission incorporate the 12 listed benefits as a minimum set of benefits for analysis but permit flexibility in how transmission providers conduct their analysis.[1570]

ii. Application of the Benefits of Long-Term Regional Transmission Facilities in Non-RTO/ISO Regions

703. Certain commenters state that all or most of the Commission's proposed benefits are applicable and appropriate in non-RTO/ISO transmission planning regions.[1571] For example, ACEG states the minimum set of benefits should be implemented as universally as possible across RTOs/ISOs and non-RTO/ISO regions.[1572] PIOs state that the Brattle-Grid Strategies Oct. 2021 Report shows the numerous benefits not currently quantified in RTO/ISO regions to consumers' detriment and that the problem is more dire in non-RTO/ISO regions.[1573] Relatedly, MISO states that benefits could be applied in non-RTO/ISO regions but may be limited or not fully realized due to less coordinated congestion management and transmission planning.[1574]

704. SEIA comments that the Commission should mandate the consideration of benefits of Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions. Otherwise, SEIA states, transmission providers could rely on state integrated resource planning processes, which do not incorporate lower cost transmission alternatives to generation procurement, potentially leading to transmission expansion to accommodate higher-cost generation than is needed. According to SEIA, there is no basis to apply different benefits in non-RTO/ISO transmission planning regions, because many of the proposed benefits of Long-Term Regional Transmission Facilities have already been calculated in non-RTO/ISO regions.[1575]

705. Southeast PIOs claim that Southeastern transmission providers should not be exempt from quantifying benefits, even if some benefits do not apply in the same manner to non-RTO/ISO transmission planning regions as they do to RTO/ISO regions.[1576] Southeast PIOs advocate for the Commission to establish standardized metrics for both RTO/ISO regions and non-RTO/ISO regions to capture similar benefits.[1577] Otherwise, Southeast PIOs argue, transmission providers will continue to focus only on costs, thereby depriving states and stakeholders of a fuller picture of transmission planning options.[1578] TAPS contends that no transmission facilities have been selected in a regional transmission plan for purposes of cost allocation since the implementation of Order No. 1000 in non-RTO/ISO transmission planning regions partly because of the narrow factors that most non-RTO/ISO regions consider in evaluating the benefits of potential transmission projects.[1579]

706. Other commenters express concern that certain NOPR benefits would be inapplicable or problematic to apply to non-RTO/ISO transmission planning regions or argue that the same types of benefits should not be applied to both sets of regions.[1580] California Municipal Utilities oppose applying the list of benefits to non-RTO/ISO transmission planning regions, stating that doing so would misapprehend the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and to provide consumer protection measures to guard against speculative transmission projects.[1581] Dominion states that a one-size-fits-all approach to benefits may be inappropriate, for instance, in locations where some transmission providers operate outside of an RTO/ISO while others function within an RTO/ISO.[1582]

707. EEI and Idaho Power state that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion or increased market liquidity.[1583] Likewise, North Carolina Commission and Staff state that some of the benefits proposed for consideration are only applicable in RTOs/ISOs (*e.g.,* increased market liquidity) and argue that some benefits could conflict with state-jurisdictional resource decisions (*e.g.,* production cost savings, access to lower-cost generation).[1584]

708. Southern states that, while certain benefits identified in the NOPR could work for Southern's non-RTO/ISO footprint, others could harm underlying state integrated resource planning/request for proposal processes or are suited only for RTO/ISO markets, such as increased market liquidity.[1585] For example, Southern states that considering production cost savings effectively would make generation resource-related decisions that would intrude into integrated resource plan/request for proposal planning, which considers the total costs (including both generation and transmission costs) of available alternatives to customers.[1586] Similarly, SERTP Sponsors state that, because SERTP Sponsors continue to use integrated resource plan/request for proposal planning to make their resource and load determinations, some of the benefits that are appropriate for consideration in RTOs/ISOs are inapplicable for transmission planning or cost allocation purposes in the Southeast.[1587] SERTP Sponsors further state that, as the states have exclusive jurisdiction over such integrated resource plan/generation matters, requiring consideration of ''[integrated resource plan/request for proposal]-related benefits,'' including production cost savings, capacity costs benefits, reduced planning reserve margins, and reduced peak energy losses, could exceed the Commission's jurisdiction by infringing on such state processes.[1588]

709. Kentucky Commission Chair Chandler argues against SERTP Sponsors' comments that suggest that integrated resource plan/request for proposal processes already consider four of the proposed categories of

[1568] PIOs Initial Comments at 37–38, 41.

[1569] Amazon Initial Comments at 5.

[1570] ENGIE Reply Comments at 3.

[1571] ACEG Initial Comments at 32, 48, 61; PIOs Initial Comments at 42; SEIA Initial Comments at 17.

[1572] ACEG Initial Comments at 32.

[1573] PIOs Initial Comments at 42.

[1574] MISO Initial Comments at 51.

[1575] SEIA Initial Comments at 17–18.

[1576] Southeast PIOs Initial Comments at 51.

[1577] *Id.* at 52.

[1578] *Id.* at 52–53.

[1579] TAPS Initial Comments at 15.

[1580] California Municipal Utilities Reply Comments at 5–6; Dominion Reply Comments at 2; Duke Initial Comments at 23; EEI Initial Comments at 19; Idaho Power Initial Comments at 8; North Carolina Commission and Staff Initial Comments at 7; Southern Initial Comments at 25–27.

[1581] California Municipal Utilities Reply Comments at 5–6.

[1582] Dominion Reply Comments at 2.

[1583] EEI Initial Comments at 19; Idaho Power Initial Comments at 8.

[1584] North Carolina Commission and Staff Initial Comments at 7.

[1585] Southern Initial Comments at 25–27.

[1586] *Id.* at 26.

[1587] SERTP Sponsors Initial Comments at 30.

[1588] SERTP Sponsors Initial Comments at 30.

benefits included in the NOPR. Kentucky Commission Chair Chandler contends that the integrated resource planning/request for proposal process can only address these four categories on a utility-by-utility basis and, thus, is unable to plan for transmission facilities across utilities or transmission planning regions by nature.[1589]

710. Some commenters advocate for or against requiring transmission providers to consider other specific lists, categories, or combinations of benefits, arguing that such approaches reduce possible duplication of benefits, increase flexibility, and/or focus on benefits they believe are most important.[1590] PIOs, for example, assert that some commenters who are opposed to the list of benefits in the NOPR nonetheless agree that transmission planners should quantify broad categories of benefits to plan effectively.[1591] AEP states that some benefits are more difficult to calculate than others and argues that the minimum set of benefits it recommends appropriately balances the significance of each type of benefit with the difficulty of quantifying that benefit.[1592]

711. AEP and GridLab argue that many of the benefits listed in the NOPR measure or identify the same type of benefit and therefore argue that the Commission should group similar benefits together into categories to avoid double-counting.[1593] Specifically, AEP and GridLab propose that the production cost savings and access to lower-cost generation benefits be grouped into a required category.[1594] In addition, AEP states that the reduced loss of load probability, reduced planning reserve margin, capacity cost benefits from reduced peak energy losses, and deferred capacity investments benefits should be combined into one required category.[1595]

712. GridLab and PJM contend that the Commission should combine the benefits of reduced loss of load probability and deferred generation capacity investment into a single category of benefits.[1596] PJM further argues that the Commission should combine the benefits of mitigation of extreme events and mitigation of weather and load uncertainty.[1597]

713. California Commission recommends that to capture the benefits of transmission infrastructure, the Commission should require transmission providers to assess benefits within the following six benefit categories: (1) production cost benefits; (2) emissions reductions benefits; (3) generation capital cost benefits; (4) risk mitigation benefits; (5) resource adequacy benefits; and (6) resilience benefits. California Commission states that such a requirement would promote greater uniformity in how the benefits of regional (and interregional) transmission projects are evaluated, reducing potential disputes over cost allocation.[1598] However, California Commission argues, the Commission should allow transmission providers, in consultation with Relevant State Entities, to define each identified benefit and determine how to quantify it.[1599] To ensure that customers are protected from speculative transmission development and unreasonably high costs, California Commission concludes that the Commission should require transmission providers to demonstrate on compliance that they identified and defined benefits within each of the required benefit categories and determined appropriate quantification methods through a transparent public process.[1600]

714. Joint Consumer Advocates state that the following categories of benefits should be included in Long-Term Regional Transmission Planning: (1) production cost savings; (2) avoided or deferred reliability transmission facilities; and (3) aging transmission infrastructure replacement.[1601]

715. AEE notes that some commenters propose that the Commission adopt a smaller set of benefit categories.[1602] AEE states that while there may be value in considering these proposals, they miss important benefits such as increased competition, market liquidity, and increased resilience from mitigation of extreme weather events effects and system contingencies.[1603] Thus, AEE recommends that the Commission adopt as mandatory the full set of 12 benefits listed in the NOPR but allow a transmission provider to demonstrate that an alternative set of benefits captures all the benefits of transmission in its transmission planning region.

716. A few commenters offer categories of benefits while noting the importance of regional flexibility.[1604] ACEG notes widespread support for the Commission to require certain categories of minimum benefits and requests flexibility for transmission providers to address these categories in accordance with regional needs. ACEG states that considering categories of benefits will reduce the risk of double-counting or miscalculating benefits and allow flexibility to apply specific benefits best suited to each transmission planning region.[1605]

717. In addition to concerns expressed by commenters in the context of the combinations of benefits proposed above, other commenters express concern regarding the potential for double-counting of benefits if transmission providers are required to consider certain benefits.[1606] For example, NRECA asserts that accounting for increased competition and increased market liquidity would risk double-counting benefits,[1607] and Utah Division of Public Utilities argues that accounting for both reduction in loss of load probability and mitigation of extreme events and system contingencies would result in double-counting.[1608] Clean Energy Buyers ask that the Commission require transmission providers to explain how they will avoid double-counting issues,[1609] while ISO–NE seeks more information from the Commission regarding which benefits the Commission believes are redundant.[1610]

[1589] Kentucky Commission Chair Chandler Reply Comments at 7.

[1590] ACEG Reply Comments at 6–7; AEE Reply Comments at 25–26; AEP Initial Comments at 6, 23–25; California Commission Initial Comments at 31–34; Certain TDUs Reply Comments at 1–2; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PIOs Reply Comments at 7–9; PJM Initial Comments at 94–96; PPL Initial Comments at 14.

[1591] PIOs Reply Comments at 7–8 (citing Entergy Initial Comments at 21; Exelon Initial Comments at 15).

[1592] AEP Initial Comments at 23.

[1593] AEP Initial Comments at 23–24; GridLab Initial Comments at 27.

[1594] AEP Initial Comments at 25; GridLab Initial Comments at 27.

[1595] AEP Initial Comments at 25.

[1596] GridLab Initial Comments at 27; PJM Initial Comments at 95.

[1597] PJM Initial Comments at 94.

[1598] California Commission Initial Comments at 33.

[1599] *Id.* at 28–29.

[1600] *Id.* at 34–35.

[1601] Joint Consumer Advocates Initial Comments at 11.

[1602] AEE Reply Comments at 25–26 (citing PJM Initial Comments at 93–96; California Commission Initial Comments at 32; New Jersey Commission Initial Comments at 13–14).

[1603] *Id.*

[1604] ACEG Reply Comments at 6–7; Entergy Initial Comments at 21.

[1605] ACEG Reply Comments at 6–7 (citing Entergy Initial Comments at 21; AEP Initial Comments at 23–27; Exelon Initial Comments at 15–16).

[1606] *See, e.g.,* APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 10–11; Louisiana Commission Reply Comments at 10; Michigan Commission Initial Comments at 6; Nevada Commission Initial Comments at 10–11; Utah Division of Public Utilities Initial Comments at 8; Vistra Initial Comments at 16–17.

[1607] NRECA Initial Comments at 45 (citing NRECA Initial Comments, attach. at 16–17).

[1608] Utah Division of Public Utilities Initial Comments at 8.

[1609] Clean Energy Buyers Initial Comments at 20–21.

[1610] ISO–NE Initial Comments at 34.

718. A few commenters state that the list of 12 benefits in the NOPR does not risk double-counting.[1611] DC and MD Offices of People's Counsel concludes that each benefit in this list is mutually exclusive, noting that some transmission providers may wish to mix and match these benefits because their modeling tools may not disaggregate them in exactly the way described in the NOPR.[1612] MISO notes that there are instances where one benefit can enable other benefits and that adopting a calculation method that recognizes that complementary behavior can yield incremental value.[1613] For example, MISO states, a calculation approach that distinguishes between the benefit of enabling resource expansion and the benefit of increased transmission capability provided by regional transmission projects would produce unique benefits.[1614]

c. Commission Determination

719. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure a set of seven required benefits (required benefits) for Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of Long-Term Regional Transmission Planning. Furthermore, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use these measured benefits to evaluate Long-Term Regional Transmission Facilities, as discussed below in the Evaluation and Selection of Regional Transmission Facilities section. This Evaluation of the Benefits of Regional Transmission Facilities section discusses this final order's requirements with regard to transmission providers' measurement and use of benefits in evaluating Long-Term Regional Transmission Facilities; however, as discussed in the Development of Long-Term Scenarios section, these same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.[1615]

720. The seven required benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, which we describe in greater detail in the discussion of the individual benefits below, are: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as 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 weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.[1616]

721. We find that these requirements are necessary to ensure that transmission providers can evaluate Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs. Specifically, we find that transmission providers must measure these seven required benefits in each Long-Term Scenario because, as discussed further in the Evaluation and Selection of Regional Transmission Facilities section, evaluating Long-Term Regional Transmission Facilities for potential selection necessarily involves the consideration of the benefits measured in each Long-Term Scenario and sensitivity to help address uncertainty over the 20-year transmission planning horizon and to maximize benefits accounting for costs over time. As such, we find that, to ensure just and reasonable Commission-jurisdictional rates, transmission providers must measure, at minimum, the set of seven required benefits in Long-Term Regional Transmission Planning and then use them to evaluate Long-Term Regional Transmission Facilities for selection.

722. Although the Commission did not propose to require the use of any specific benefits in the NOPR, the Commission sought comment on whether it should require transmission providers to use some or all of the potential benefits described in the NOPR as a minimum set of benefits in Long-Term Regional Transmission Planning. The record in this proceeding shows that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it is necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. We find that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

723. By requiring the measurement and use of the seven enumerated benefits in Long-Term Regional Transmission Planning, we ensure that transmission providers will consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. In contrast, adopting the more flexible approach proposed in the NOPR would not address the identified deficiencies in existing regional transmission planning and cost allocation processes because such an approach would fail to ensure that transmission providers consider the broader set of benefits provided by, and the beneficiaries receiving the benefits of, Long-Term Regional Transmission Facilities, and thus, may fail to identify the potentially more efficient or cost-effective regional transmission solution. We find that failing to use the set of benefits that we require in this final order to evaluate Long-Term Regional Transmission Facilities for potential selection could render resulting Commission-jurisdictional rates unjust and unreasonable. We find that not requiring transmission providers to use certain benefits to evaluate Long-Term Regional Transmission Facilities would be expected to lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected.[1617] In addition, we find that the transparency provided by requiring consideration of a sufficiently broad and common set of benefits will help to ensure the costs of Long-Term Regional Transmission Facilities are allocated to beneficiaries in a manner that is at least

[1611] DC and MD Offices of People's Counsel Initial Comments at 20; MISO Initial Comments at 50.

[1612] DC and MD Offices of People's Counsel Initial Comments at 20.

[1613] MISO Initial Comments at 50.

[1614] *Id.*

[1615] *See supra* Long-Term Regional Transmission Planning, Development of Long-Term Scenarios section.

[1616] We discuss modifications to Benefit 6 from its description in the NOPR in the Benefit 6 determination section.

[1617] *See* Clean Energy Associations Initial Comments at 20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses,* at 26 (Apr. 2021)).

roughly commensurate with the benefits they derive from them.[1618]

724. We appreciate arguments made by certain commenters that failure to incorporate identifiable benefits risks skewing the evaluation process against developing needed and beneficial Long-Term Regional Transmission Facilities because transmission providers would consider all of the costs of such transmission facilities without similarly considering many important benefits that they may provide.[1619] However, we are also cognizant of concerns about duplication of benefits and difficulty of measuring certain benefits. In this final order, rather than requiring transmission providers to measure and use all 12 benefits enumerated in the NOPR, we only require transmission providers to measure and use seven specific benefits that have a proven track record, can be discretely measured, and are unlikely to cause duplication. We find that the modification to the NOPR proposal to require the measurement and use of these seven benefits to evaluate Long-Term Regional Transmission Facilities, as discussed above, resolves concerns about important benefits being omitted from Long-Term Regional Transmission Planning, as well as challenges raised concerning duplication and measurement of certain benefits.

725. We acknowledge that many commenters do not favor requiring the use of particular benefits. In response, we emphasize that a set of common benefits and a requirement to measure and use those benefits in Long-Term Regional Transmission Planning will ensure just and reasonable rates, as discussed above.[1620] Specifically, unless transmission providers consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs, they may fail to identify the more efficient or cost-effective regional transmission solution, resulting in relatively inefficient or less cost-effective transmission development.

726. We note that some commenters request flexibility to use different benefits, such as SPP, which states that the effort required to incorporate additional benefit metrics into its current regional transmission planning process cannot be accommodated within its current process timeline.[1621] As discussed in the Implementation and Compliance sections of this final order, we require transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles), and thus transmission providers will not be required to immediately implement this reform.

727. Some commenters argue that the requirement to measure and use these benefits will increase costs and require additional effort, and that the Commission has presented insufficient evidence that this requirement will produce the desired benefits.[1622] Commenters who express such concerns did not provide persuasive evidence to suggest that requiring the measurement and use of a required set of benefits would be unduly burdensome. While measuring these benefits may impose a degree of burden on some transmission providers, the requirement for transmission providers to measure and use the seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that rates are just and reasonable. Specifically, absent a requirement that transmission providers measure and use a sufficiently broad range of benefits of Long-Term Regional Transmission Facilities when evaluating them for potential selection, transmission providers may not identify, evaluate, and select more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs, which may lead to relatively inefficient or less cost-effective transmission development. Further, we believe that experience gained by transmission providers will over time allow them to perform the necessary measurements more efficiently. Moreover, in our discussion of each required benefit below, we provide a description, for several of the required benefits, of at least one manner in which transmission providers could measure each required benefit. Finally, commenters also did not provide persuasive evidence that the burdens of measuring and using a required set of benefits outweigh the benefits of using these benefits in Long-Term Regional Transmission Planning. We therefore find that any burdens of measuring and using the seven required benefits in Long-Term Regional Transmission Planning are outweighed by the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs.[1623]

728. Another common concern expressed by some commenters is that requiring a minimum set of benefits would undermine regional flexibility.[1624] We conclude that it would be inappropriate to provide flexibility not to consider this required set of benefits in Long-Term Regional Transmission Planning because, as described above, requiring the measurement and use of these benefits ensures that transmission providers are able to identify, evaluate, and select regional transmission solutions to more efficiently or cost-effectively address Long-Term Transmission Needs, and thereby ensures just and reasonable rates. We therefore disagree with Dominion that transmission providers should be permitted to identify initial benefits that they will consider in

[1618] *ICC* v. *FERC I,* 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 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).

[1619] *See* Enel Initial Comments at 3.

[1620] *See* ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at 6, 23–25; Breakthrough Energy Initial Comments at 4, 21–22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11–12; Clean Energy Buyers Reply Comments at 8–9; Concerned Scientists Reply Comments at 7–10; Cypress Creek Reply Comments at 7–8; DC and MD Offices of People's Counsels Reply Comments at 3, 7–8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16: Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18–22; Interwest Initial Comments at 12; Interwest Reply Comments at 6–7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11–14; Pacific Northwest State Agencies Initial Comments at 16–17; PIOs Initial Comments at 27–28; PIOs Reply Comments at 7–8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16–17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; ; US DOE Initial Comments at 30–33; US Senator Schumer Supplemental Comments at 1–2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

[1621] SPP Initial Comments at 18.

[1622] *E.g.,* Dominion Initial Comments at 34–35.

[1623] *See* Clean Energy Associations Initial Comments at 20 (''Not requiring benefits to be evaluated could lead to higher costs in the long-term, and, thus, unjust and unreasonable rates.'').

[1624] *E.g.,* Entergy Initial Comments at 21.

conducting Long-Term Regional Transmission Planning but retain flexibility in applying such benefits to each transmission provider's individual circumstances.[1625] However, as we discuss further below, we are providing flexibility to transmission providers regarding how they will measure each of the required benefits.

729. Transmission providers may also propose to measure and use additional benefits in Long-Term Regional Transmission Planning, as discussed below in the Other Benefits section. This approach provides flexibility to transmission providers in how they implement the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning, while maintaining the baseline requirement that they measure and use all seven benefits included in that required set of benefits, in order to ensure that rates remain just and reasonable. Requiring all transmission providers to measure and use a required set of benefits will help to improve interregional transmission coordination among different transmission planning regions, as noted by commenters.[1626]

730. In addition, as more fully described below, we also find that the seven benefits we require are not overly burdensome to calculate. We address such concerns for individual benefits in more detail within the determination section on each benefit below.

731. Some commenters assert that some benefits are only appropriate for use in RTO/ISO transmission planning regions.[1627] We believe that all seven required benefits can be calculated in both RTO/ISO and non-RTO/ISO transmission planning regions, as noted by ACEG.[1628] In particular, we note that all seven required benefits have either been approved for use in regional transmission planning in at least one non-RTO/ISO transmission planning region or may be implemented by building upon the modeling or techniques used to measure benefits in RTO/ISO or non-RTO/ISO regions, or both.

732. As described below, in the NOPR, the Commission noted that it approved the use of production cost savings (*i.e.,* Benefit 3) to evaluate Order No. 1000 economic transmission projects in a non-RTO/ISO transmission planning region.[1629] We note that, as measurements of reduced production costs outside of normal conditions, the measurement methods for Benefit 5, Reduced Congestion Due to Transmission Outages, and Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, may be built upon the modeling used to measure Benefit 3. Separately, the Commission has accepted use of benefits in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,[1630] and Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.[1631] In the NOPR, the Commission likewise noted that it has accepted accounting for the avoided costs (*i.e.,* Benefit 1) as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO transmission planning regions.[1632] With respect to Final Order Benefit 7 (*i.e.,* capacity cost benefits from reduced peak energy losses), the avoided costs associated with this benefit are comparable across RTO/ISO and non-RTO/ISO transmission planning regions. Transmission providers in all transmission planning regions incur capital costs to meet installed generation requirements and to maintain reliable operations. Transmission expansions may help reduce peak energy losses, and under this benefit, result in capital cost savings associated with the reduction in installed generation requirements.

733. We disagree with commenters that express concerns that required benefits would conflict with state-regulated integrated resource planning processes.[1633] As discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, nothing in this final order infringes on the states' reserved authority under FPA section 201.

734. Entergy argues that the Commission should recognize that not all benefits are created equal for all jurisdictions and that some states will want transmission projects that actually reduce customer bills to have clear priority.[1634] We believe that the required measurement and use of the required set of benefits can accommodate such preferences. Our requirements ensure that all benefits are measured transparently and considered in selection decisions. In addition, our required set of benefits captures considerations such as production cost savings that can flow through to customer bills. PJM, for example, notes that lower production costs will generally also reduce market prices for electricity as lower-cost suppliers will set market clearing prices more frequently than without the transmission project.[1635] We note that while this final order requires the measurement and use of the required set of benefits, it is the evaluation process, including selection criteria, that transmission providers propose on compliance that will inform which Long-Term Regional Transmission Facilities are selected. Transmission providers may propose an evaluation process, including selection criteria, that reflect regional preferences as long as those criteria meet the requirements set forth below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section.

735. ISO–NE notes that the Commission sought information on potential double-counting of benefits and requests that the Commission clarify which benefits the Commission believes are redundant.[1636] We believe that the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting. Nonetheless, to the extent that transmission providers are concerned that any possibility of double-counting remains, we provide transmission providers with flexibility on the measurement of such benefits and expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address those concerns.

736. Some commenters urge the Commission to adopt a combination or categorical approach toward benefits, under which required benefits would be grouped under certain categories or combinations.[1637] We decline to adopt

[1625] Dominion Initial Comments at 34.

[1626] Breakthrough Energy Initial Comments at 22–23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27–28; US DOE Initial Comments at 31–32.

[1627] Pacific Northwest Utilities Initial Comments at 8–10; SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 25–27.

[1628] ACEG Initial Comments at 48.

[1629] NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206, at P 314 (2013)).

[1630] *PacifiCorp,* 147 FERC ¶ 61,057, at PP 133–134, 141–143 (2014); *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206 at P 314.

[1631] *PacifiCorp,* 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

[1632] NOPR, 179 FERC ¶ 61,028 at PP 189–190 & n.326 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

[1633] SERTP Sponsors Initial Comments at 30; Southern Initial Comments at 24–26.

[1634] Entergy Initial Comments at 21.

[1635] PJM Initial Comments at 95.

[1636] ISO–NE Initial Comments at 34.

[1637] ACEG Reply Comments at 6–7; AEP Initial Comments at 23–25; California Commission Initial this approach, largely because our analysis and review of the record suggests that such an approach could reduce transparency regarding the benefits that we are requiring. For example, in some cases adopting a combination or categories approach could obfuscate individual benefit calculations within a category, making it less clear to interested parties what specific benefits a Long-Term Regional Transmission Facility may provide. Additionally, we find that these seven benefits merit individual measurement and evaluation.

737. Northwest and Intermountain and NYISO ask that the final order confirm that the 12 illustrative benefits described in the NOPR are not exhaustive.[1638] First, we confirm that the list of 12 illustrative benefits described in the NOPR is not an exhaustive list of the potential benefits of Long-Term Regional Transmission Facilities. Second, we reiterate that the required set of benefits adopted in this final order is a subset of the benefits listed in the NOPR, as modified in the discussions below. Transmission providers may be aware of additional benefits beyond those included in the required set of benefits, or the 12 illustrative benefits described in the NOPR, and we provide them with the flexibility to propose to measure and use additional benefits in Long-Term Regional Transmission Planning so long as they do so in a manner that is consistent with transmission providers' obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes. In particular, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected to address Long-Term Transmission Needs.[1639] This necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits that we require transmission providers to include in their OATTs. We find that this transparency strikes an appropriate balance between ensuring that transmission providers measure and use the seven required benefits in Long-Term Regional Transmission Planning and allowing flexibility for transmission providers to use additional benefits that they believe will reasonably reflect the benefits of a Long-Term Regional Transmission Facility or Facilities in their transmission planning regions.

738. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.[1640] We clarify that transmission providers must use the required set of benefits to evaluate Long-Term Regional Transmission Facilities in every Long-Term Regional Transmission Planning cycle, and we discuss the use of other benefits to evaluate Long-Term Regional Transmission Facilities in the Other Benefits section of this final order.

739. Some commenters suggest that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before investing staff resources and modeling work to provide a detailed quantification.[1641] Clean Energy Buyers similarly argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits described in the NOPR and quantify them accordingly.[1642] We find such screening approaches, as advocated by some commenters, to be inconsistent with the approach we adopt in this final order, which requires measurement and use of each of the seven required benefits in Long-Term Regional Transmission Planning, and we are concerned that permitting the use of screens could undermine this requirement. We therefore do not allow transmission providers to use a screening approach when measuring the seven required benefits.

2. Required Benefits

a. The Seven Required Benefits

i. Benefit 1: Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement

(a) NOPR Description

740. The Commission described this benefit in the NOPR as the reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. The Commission stated that, recognizing that regional transmission planning could lead to the development of transmission facilities that span the service territories of multiple transmission providers, which in turn would obviate the need for transmission facilities that would otherwise be identified in multiple local transmission plans, the Commission has accepted accounting for such ''avoided costs'' as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO regions.[1643] The Commission noted that, in using this method, transmission providers in a transmission planning region determine the beneficiaries of a regional transmission facility or portfolio of facilities by identifying the local and regional transmission facilities that a new proposed regional transmission facility or portfolio of facilities would displace. The Commission described the method as defining the benefits of the regional transmission facility or facilities as the costs that transmission providers in the transmission planning region ''avoid'' because they no longer need to build the displaced local and regional transmission facilities. Further, the Commission stated that the method allocates costs among transmission providers whose local or regional transmission facilities the new proposed regional transmission facility or facilities would displace in proportion to their share of the total benefits (*i.e.,* the total avoided costs). If the new proposed regional transmission facility or facilities do not displace any local or regional transmission facilities in existing local or regional transmission plans, the Commission discussed that the avoided cost method determines the benefits of the applicable facilities by considering the costs of local or regional transmission facilities that would otherwise be needed to meet the same need that the new proposed regional transmission facility will meet.[1644] The Commission noted that, in calculating this benefit, transmission providers in each transmission planning region could first identify transmission facilities that could defer or replace an identified reliability transmission solution. Avoided cost benefits could be calculated by comparing the cost of

Comments at 33; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PJM Initial Comments at 94–96.

[1638] Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

[1639] *See infra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[1640] OMS Initial Comments at 8.

[1641] ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9; Interwest Initial Comments at 12–13; WATT Coalition Initial Comments at 7.

[1642] Clean Energy Buyers Initial Comments at 20–21.

[1643] NOPR, 179 FERC ¶ 61,028 at PP 189–190 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

[1644] NOPR, 179 FERC ¶ 61,028 at P 190 (citing *S.C. Elec. & Gas Co.,* 143 FERC ¶ 61,058, at P 232 (2013)).

transmission facilities required to address the reliability need without the proposed regional transmission facility to the cost of transmission facilities needed to address the reliability need assuming the regional transmission solution were in place.[1645]

741. The Commission noted that Benefit 1 could also include the separate benefits stream caused by a deferral of replacement of other transmission facilities through identification and selection of a transmission facility or facilities. This could be measured through calculation of the present value savings for the period of deferral of additional replacement transmission facilities multiplied by their estimated capital cost.[1646] The Commission also noted that a number of transmission providers already evaluate the avoided or deferred costs of reliability transmission projects. For example, SPP uses a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a potential reliability transmission facility. The costs of these avoided or delayed reliability transmission facilities are used to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.[1647] The Commission stated that transmission providers could also use avoided costs to calculate the benefits of replacing aging transmission facilities. The Commission provided NYISO as an example, which estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.[1648]

(b) Comments

742. A number of commenters support mandating consideration of Benefit 1.[1649] ACEG, for example, supports inclusion of this benefit, asserting that reliability considerations and replacing aging assets are responsible for almost all current transmission spending.[1650] However, MISO states that, when capturing avoided transmission investment benefits, care must be exercised to avoid the counting of benefits associated with facility overloads that are identified in reliability studies and directly addressed by regional transmission projects. MISO indicates that this approach is necessary because the adjusted production cost savings benefits already reflect the congestion associated with these facility overloads.[1651] Southern states that this benefit would likely prove workable under its non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of ''avoided costs.'' [1652]

743. Several commenters oppose or express concerns with mandating consideration of Benefit 1.[1653] West Virginia Commission argues that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1654] Xcel states that benefit calculations can be different between the short-term regional transmission planning process and Long-Term Regional Transmission Planning and that, for example, it would likely be unreasonable to determine reliability benefits in Long-Term Regional Transmission Planning using the avoided cost of local reliability solutions.[1655]

744. NARUC states that, while Benefit 1 seems capable of calculation, it carries with it a degree of risk if aging transmission infrastructure continues to be operated. For instance, NARUC indicates that some wildfires have been linked to deferred transmission maintenance of aging infrastructure.[1656] AEE responds by stating that the Commission should clarify: (1) its expectations regarding its calculation; and (2) that regional transmission built for inherently economic or public policy purposes has, when installed, avoided reliability cost benefits.[1657] AEE argues that calculating the benefits of avoided investment in reliability or replacement facilities should not create an environment for continuously putting ''band aid'' fixes on aging systems that should instead be replaced to ensure reliability and resilience.[1658]

(c) Commission Determination

745. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 1 as the reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. We find that requiring the measurement and use of Benefit 1, as described, is necessary because Long-Term Regional Transmission Facilities may obviate or delay the need for reliability transmission facilities identified in the near term, or the need for later replacements of aging transmission infrastructure. Requiring transmission providers to measure and use the benefits associated with avoiding or delaying such transmission needs will help to ensure that, when conducting Long-Term Regional Transmission Planning, transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

746. We note that a number of transmission providers already evaluate avoided or deferred costs of reliability transmission facilities. ACEG states that Benefit 1 reflects that reliability considerations and replacing aging assets drive significant investment in transmission and account for almost all current transmission spending.[1659] SPP employs a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a

[1645] *Id.* P 191 (citing Brattle-Grid Strategies Oct. 2021 Report at 37).

[1646] *Id.* P 192.

[1647] *Id.* P 193 (citing SPP, *SPP Benefit Metrics Manual,* SPP Engineering, at 15 (Nov. 6, 2020)).

[1648] *Id.* P 193 (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades,* at 114 (Sept. 15, 2015)).

[1649] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25 (including Benefit 1 in its recommended minimum set of benefit categories); Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Certain TDUs Reply Comments at 1–2; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11–13; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1650] ACEG Initial Comments at 34–35.

[1651] MISO Initial Comments at 50.

[1652] Southern Initial Comments at 25.

[1653] Joint Consumer Advocates Initial Comments at 11; NARUC Initial Comments at 22; West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

[1654] West Virginia Commission Supplemental Comments at 4.

[1655] Xcel Initial Comments at 13.

[1656] NARUC Initial Comments at 22.

[1657] AEE Reply Comments at 26 (citing NARUC Initial Comments at 22).

[1658] *Id.*

[1659] ACEG Initial Comments at 34–35.

potential reliability transmission facility, using the costs of these avoided or delayed reliability transmission facilities to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.[1660] Additionally, NYISO estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.[1661] We find that widespread use of this benefit contradicts West Virginia Commission's assertion that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance, as well as similar assertions by Xcel.[1662]

747. We agree with NARUC and AEE that continued operation of aging infrastructure can carry risks if it is not properly maintained.[1663] We note that nothing in this final order restricts an incumbent transmission provider from developing a local transmission facility to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.[1664] Such a solution would not be subject to approval at the regional or interregional level where the transmission provider does not seek to have it selected as a regional transmission facility for purposes of cost allocation.[1665] Moreover, nothing in this final order requires transmission providers to keep transmission facilities in operation beyond their useful life. We emphasize that transmission providers can use Benefit 1 to calculate the costs that are avoided because replacements of local or regional transmission facilities are no longer needed, or may be deferred, when they are displaced by proposed new Long-Term Regional Transmission Facilities.

ii. Benefit 2(a): Reduced Loss of Load Probability or Benefit 2(b): Reduced Planning Reserve Margin

(a) NOPR Description

748. The Commission described this benefit in the NOPR as being measured in one of two ways: (a) using reduced loss of load probability *or* (b) reduced planning reserve margin. The Commission noted that, because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, a single transmission facility can either reduce loss of load events if the planning reserve margin is unchanged or allow for the reduction in planning reserve margins if loss of load events remain constant, but not both simultaneously.[1666]

749. The Commission described Benefit 2(a) in the NOPR as reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events.[1667] The Commission noted that transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period. The Commission noted that one example of how a reduction of loss of load probability benefit could be calculated can be found in a report by SPP's Metrics Task Force. The report proposes quantifying the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, obtaining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a transmission expansion.[1668]

750. The Commission described Benefit 2(b) in the NOPR as reduced planning reserve margin, or ''the reduction in capital costs of generation needed to meet resource adequacy requirements (*i.e.,* planning reserve margins) while holding loss of load probability constant.'' [1669] The Commission stated that investments in transmission capacity can reduce the system-wide planning reserve margin requirement or the reserve margin requirement within individual resource adequacy zones of a transmission planning region, which can reduce the need for generation capital expenditures.[1670] The Commission also stated that it is important to note that, due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with loss of load probability, only one of these benefits should be calculated for a transmission investment, but not both simultaneously.[1671] The Commission noted that RTOs/ISOs have calculated the transmission benefits of reduced planning reserve margins. MISO, for example, calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, which reduced the need for future generation buildout to meet reserve requirements, by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of $1.0 to $5.1 billion in benefits over 10 years.[1672]

(b) Comments

751. A number of commenters support mandating consideration of Benefit 2(a).[1673] Some commenters discuss the manner in which this benefit should be calculated.[1674] ACEG and DC and MD Offices of People's Counsel note the importance of geographic diversity between transmission planning regions as an important consideration in evaluating this benefit.[1675] Specifically, ACEG states that it can be estimated using the

[1660] NOPR, 179 FERC ¶ 61,028 at P 193 (citing SPP, *SPP Benefit Metrics Manual,* SPP Engineering, at 15 (Nov. 6, 2020)).

[1661] *Id.* (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades,* at 114 (Sept. 15, 2015)).

[1662] West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

[1663] AEE Reply Comments at 26 (citing NARUC Initial Comments at 22); NARUC Initial Comments at 22.

[1664] Order No. 1000, 136 FERC ¶ 61,051 at PP 262, 329.

[1665] *Id.* P 384.

[1666] NOPR, 179 FERC ¶ 61,028 at P 194.

[1667] *Id.*

[1668] *Id.* P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review,* at 25 (Sept. 13, 2012)).

[1669] *Id.* P 194.

[1670] *Id.* P 196.

[1671] *Id.*

[1672] *Id.* P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop,* at 36–38 (Sept. 19 & 29, 2011)).

[1673] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1674] *E.g.,* ACEG Initial Comments at 38–39.

[1675] ACEG Initial Comments at 35–38; DC and MD Offices of People's Counsel Initial Comments at 21–24.

value of lost load and generation capital cost savings due to lower needed planning reserve margins.[1676]

752. However, some commenters oppose or express concerns regarding mandating consideration of Benefit 2(a).[1677] NARUC states that transmission planners are likely already considering loss of load events in their evaluations of system expansions and that whether such benefit, in isolation, is sufficient to recommend construction of a particular transmission project is a question best left to them and their states.[1678] West Virginia Commission argues that calculation of benefits from reduced loss of load probability requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1679] R Street states that Benefit 2(a) should be refined to the avoided value of lost load so that it is compatible with an economic assessment, while Illinois Commission asserts that the Commission should consider a more expansive definition of reduced loss of load probability composed of more than one metric, such as value of lost load, expected unserved energy, or a hybrid measure, that can serve as a supplement to loss of load expectation.[1680]

753. With respect to Benefit 2(b), a number of commenters support mandating consideration of this benefit.[1681] AEP recommends including Benefit 2(b) as a part of a combination of benefits.[1682] Pine Gate states that this proposed benefit is critical to address resource adequacy concerns, particularly where a transmission planning region relies heavily on a single generation type.[1683]

754. With respect to comments in opposition to Benefit 2(b), similar to its comments on Benefit 2(a) above, West Virginia Commission argues that calculation of benefits from reduced planning reserve margin requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1684]

(c) Commission Determination

755. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 2, in Long-Term Regional Transmission Planning. This benefit can be characterized and measured as Benefit 2(a), Reduced Loss of Load Probability, or as Benefit 2(b), Reduced Planning Reserve Margin, and we clarify that these are different methods for measuring the same underlying benefit. We find that requiring the measurement and use of this benefit is necessary because it reflects an important category of reliability benefits of Long-Term Regional Transmission Facilities. Because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, for purposes of Long-Term Regional Transmission Planning, transmission providers must either measure reduced loss of load events by holding the planning reserve margin constant *or* measure the reduction in planning reserve margins by holding loss of load events constant but may not measure both simultaneously for purposes of using and measuring Benefit 2(a) or 2(b).

756. We adopt the NOPR's proposed description of Benefit 2(a) that describes Benefit 2(a), Reduced Loss of Load Probability, as the reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events. Benefit 2(a) measures reduced loss of load probability for resource adequacy planning, which typically includes the consideration of normal system conditions. One method of measuring a reduction in loss of load probability benefit is to quantify the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, determining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a Long-Term Regional Transmission Facility or a portfolio of Long-Term Regional Transmission Facilities.[1685]

757. Numerous commenters support mandating Benefit 2(a).[1686] We recognize commenter suggestions regarding the method for calculating this benefit, with some recommending consideration of geographic diversity between transmission planning regions[1687] and others recommending that the benefit be expressed in terms of the value of lost load.[1688] We agree that geographic diversity is an important consideration in evaluating the reduced loss of load probability method of calculating this benefit and find that the flexibility in measuring benefits that we provide to transmission providers under this final order allows for this consideration. As to the suggestion by Illinois Commission and R Street that Benefit 2(a) should be expressed in terms of the value of lost load so that it can be expressed in terms of cost, we believe that either Benefit 2(a) or Benefit 2(b) are reasonable methods to calculate Benefit 2 and we reiterate that transmission providers can choose either method to calculate this benefit. We encourage transmission providers to consider whether Benefit 2(a) or Benefit 2(b) is the most effective way to accurately reflect the benefits of a proposed Long-Term Regional Transmission Facility in their individual regions. As to NARUC's contention that the benefit of reducing the probability of loss of load events, in isolation, may be insufficient to support the development of a particular

[1676] ACEG Initial Comments at 38.

[1677] NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1678] NARUC Initial Comments at 23.

[1679] West Virginia Commission Supplemental Comments at 4.

[1680] Illinois Commission Initial Comments at 14; R Street Initial Comments at 9.

[1681] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

[1682] AEP Initial Comments at 25.

[1683] Pine Gate Initial Comments at 37.

[1684] West Virginia Commission Supplemental Comments at 4.

[1685] NOPR, 179 FERC ¶ 61,028 at P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review,* at 25 (Sept. 13, 2012)).

[1686] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25: AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1687] ACEG Initial Comments at 35–38; DC and MD Offices of People's Counsel Initial Comments at 21–24.

[1688] Illinois Commission Initial Comments at 14 (suggesting alternatively that Benefit 2(a) be expressed in terms of expected unserved energy, or a hybrid measurement composed of more than one metric); R Street Initial Comments at 9 (stating that using value of lost load is compatible with an economic assessment).

transmission project, while we are requiring transmission providers to use Benefit 2(a) or Benefit 2(b) to evaluate Long-Term Regional Transmission Facilities, we are not requiring transmission providers to base their evaluation on this single benefit—or any single benefit, for that matter—but rather on at least the range of benefits included in the required set of benefits that we adopt herein. Moreover, we are not requiring that transmission providers select any Long-Term Regional Transmission Facility.

758. As noted above, the NOPR proposed the following description of Benefit 2(b), ''the reduction in capital costs of generation needed to meet resource adequacy requirements (*i.e.,* planning reserve margins) while holding loss of load probability constant.'' [1689] We adopt the NOPR description in this final order. We find that a lower planning reserve margin is another way to demonstrate a resource adequacy benefit. As we indicate above, due to the relationship between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with reduced loss of load probability, only one of these methods for calculating the benefit for a transmission investment can be used, but not both simultaneously. We find that Benefit 2(b) is one of two ways to calculate reduced costs related to resource adequacy because Long-Term Regional Transmission Facilities can reduce the system-wide planning reserve margin requirements within individual resource adequacy zones of a transmission planning region and provide benefits by reducing the need for generation capital expenditures.

759. Many commenters support mandating consideration of Benefit 2(b). For example, DC and MD Offices of People's Counsel note that the benefit of a reduced reserve planning margin has been used in multiple cases.[1690] We also find that it is feasible for transmission providers to calculate the benefit of reduced planning reserve margins. We reiterate here the example of MISO, which calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, reducing the need for future generation investments to meet reserve requirements by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of $1.0 to $5.1 billion in benefits over 10 years.[1691] We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,[1692] in non-RTO/ISO transmission planning regions.[1693]

760. Finally, we disagree with West Virginia Commission's claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1694] As noted above, there are multiple examples in the record of transmission providers that currently calculate these benefits. Because we find that transmission providers will be able to calculate either Benefit 2(a) or 2(b) and recognize the importance of accounting for Benefit 2 in Long-Term Regional Transmission Planning, we require transmission providers to measure and use Benefit 2.

iii. Benefit 3: Production Cost Savings

(a) NOPR Description

761. The Commission described Benefit 3 in the NOPR as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices.[1695] The Commission stated that most regional transmission planning processes currently estimate production cost savings. Generally, within RTOs/ISOs, security-constrained production cost models simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints. The traditional method for estimating the changes in adjusted production costs associated with proposed transmission facilities (or portfolio of facilities) is to compare the adjusted production costs with and without those facilities. Analysts typically call the market simulations without the proposed transmission facilities the ''Base Case'' and the simulations with those facilities the ''Change Case.'' [1696]

762. The Commission further explained that approaches used to calculate production cost savings vary. MISO uses production cost savings (adjusted for import costs and export revenues) to allocate the costs of its Market Efficiency Projects to cost allocation zones based on each zone's share of the total adjusted production cost savings.[1697] The Commission also explained, in contrast, that NYISO and PJM use reductions to load energy payments (adjusted to reflect the reduced value of transmission congestion contracts) to allocate the costs of economic transmission facilities.[1698]

763. The Commission stated that non-RTO/ISO regions, without centrally organized energy markets, rely on other tools to perform analyses of production cost savings. For example, WestConnect's regional cost allocation method for regional transmission facilities driven by economic considerations identifies the benefits and beneficiaries of a proposed regional transmission facility or facilities by modeling the potential of the transmission facilities to support more economic bilateral transactions between generators and loads in the region. Specifically, WestConnect considers the transactions between loads and lower-

[1689] NOPR, 179 FERC ¶ 61,028 at P 194.

[1690] DC and MD Offices of People's Counsel at 22–23 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop,* at 36–38 (Sept. 19 & 29, 2011); SPP, *Benefits for the 2013 Regional Cost Allocation Review* (Sept. 13, 2012); *Investigation on Comm'n's Own Motion to Review 18 Percent Planning Reserve Margin Requirement,* Docket No. 5–EI–141 (PSC REF# 102692), at 5 (Pub. Serv. Comm'n Wis. Oct. 9, 2008); SPP, *The Value of Transmission,* at 16 (Jan. 26, 2016); Midcontinent Independent System Operator, Inc., *MISO Value Proposition 2020: Forward View,* at 20–21 (June 2022); PJM Interconnection, L.L.C., *PJM Value Proposition,* at 2 (2019); Australian Energy Market Operator, *2022 Integrated System Plan,* at 64 (June 2022)).

[1691] NOPR, 179 FERC ¶ 61,028 at P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop,* at 36–38 (Sept. 19 & 29, 2011)).

[1692] *PacifiCorp,* 147 FERC ¶ 61,057 at PP 133–134, 141–143; *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206 at P 314.

[1693] *PacifiCorp,* 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

[1694] West Virginia Commission Supplemental Comments at 4.

[1695] NOPR, 179 FERC ¶ 61,028 at P 198 & n.333 (proposing to define this as adjusted production cost savings when the calculation is adjusted to account for purchases and sales outside the region).

[1696] NOPR, 179 FERC ¶ 61,028 at P 199.

[1697] NOPR, 179 FERC ¶ 61,028 at P 200 (citing MISO, FERC Electric Tariff, attach. FF, Benefit Metrics section (I)(A)(1) (33.0.0)).

[1698] NOPR, 179 FERC ¶ 61,028 at P 200 & n.335 (citing *PJM Interconnection L.L.C.,* 142 FERC ¶ 61,214 at P 416; *N.Y. Indep. Sys. Operator Corp.,* 143 FERC ¶ 61,059, at PP 268, 269, n.516 (2013); NYISO, NYISO Tariffs, OATT, attach. Y, section 31.5 (Cost Allocation and Cost Recovery) (30.0.0), section 31.5.4.3.2.) (''For high voltage economic transmission facilities, PJM allocates 50% of the costs in accordance with its economic analysis and allocates the other 50% of the costs on a load-ratio share basis.'').

cost generation that a proposed regional transmission facility could support and, accounting for the costs associated with transmission service, identifies the transactions that are likely to occur. WestConnect then estimates any resulting cost savings (in the form of reductions in production costs and reserve sharing requirements) and allocates the costs of the regional transmission facilities on that basis.[1699]

(b) Comments

764. A number of commenters support mandating consideration of this benefit.[1700] AEP recommends including Benefit 3 as a part of a combination of benefits.[1701] According to TAPS, all of the RTOs/ISOs already consider production cost savings; TAPS argues that the Commission should require transmission providers in non-RTO/ISO transmission planning regions to consider them as well.[1702] Indicated PJM TOs state that this benefit is one of the main benefits that will drive the selection of transmission facilities in PJM.[1703]

765. Some commenters opine on how to calculate this benefit.[1704] ACEG states that production cost savings should include fuel and variable operating cost savings, adjustments for imports from neighboring transmission planning regions, reduced costs of cycling power plants, reduced amounts and costs of operating reserves and other ancillary services, and mitigation of reliability-must-run conditions.[1705] Likewise, DC and MD Offices of People's Counsel state that production cost savings should include ancillary service cost savings.[1706] MISO notes that, in addition to evaluating production cost savings under normal patterns of renewable dispatch and load, transmission providers can analyze production cost savings that accrue during transmission outages using historical sampling or statistical modeling of transmission outage patterns.[1707] MISO TOs state that its process to evaluate Multi-Value Projects considers production cost savings that can be realized through reduced transmission congestion and transmission energy losses, capacity loss savings, capacity savings, long-term cost savings, and ''any other financially quantifiable benefit.''[1708]

766. Some commenters oppose or express concerns regarding mandating consideration of production cost savings.[1709] For example, Southern states that considering production cost savings could result in the double-counting of benefits in its footprint by, for example, making generation pricing/cost decisions that have already been made or will ultimately be made in integrated resource planning or request for proposal processes.[1710] Relatedly, North Carolina Commission and Staff state that requiring consideration of production cost savings would conflict with state-jurisdictional resource decisions.[1711] Mississippi Commission contends that this benefit may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.[1712] PJM Market Monitor states that in PJM, comparing production cost savings across different gas prices and different generation resource capacity may not provide meaningful guidance as to the benefits of a transmission facility beyond that currently provided by satisfying reliability criteria because of potentially inaccurate forecasts for key values.[1713] Pacific Northwest Utilities assert that this benefit is not easily quantifiable.[1714]

(c) Commission Determination

767. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 3, Production Cost Savings, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 3 as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices. We find that requiring the use of Benefit 3 is necessary because Long-Term Regional Transmission Facilities could result in savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production. We further find that, absent a requirement for transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

768. We do not require a standardized method for measuring production cost savings, and, consistent with this approach, we decline commenter requests to specify the exact types of cost savings for which transmission providers must account when measuring this benefit.[1715] As the Commission stated in the NOPR,[1716] different transmission planning regions have different approaches toward the calculation of this benefit, and this final order provides flexibility for transmission providers in developing the method that they use to measure production cost savings, consistent with the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning described above.

[1699] NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206 at P 314).

[1700] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Certain TDUs Reply Comments at 1–2; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Joint Consumer Advocates Initial Comments at 11; New Jersey Commission Initial Comments at 13–14 (including reduced production costs during transmission outages, extreme events, and higher than normal load conditions in Benefit 3); Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; TAPS Initial Comments at 14; US DOE Initial Comments at 31–32.

[1701] AEP Initial Comments at 25.

[1702] TAPS Initial Comments at 14.

[1703] Indicated PJM TOs Initial Comments at 17.

[1704] ACEG Initial Comments at 40; DC and MD Offices of People's Counsel Initial Comments at 25; GridLab Initial Comments at 26–27; MISO Initial Comments at 49–50.

[1705] ACEG Initial Comments at 40.

[1706] DC and MD Offices of People's Counsel Initial Comments at 25.

[1707] MISO Initial Comments at 49–50.

[1708] MISO TOs Initial Comments at 21 (citing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, attach. FF (90.0.0), section II.C.5).

[1709] Mississippi Commission Initial Comments at 35–36; North Carolina Commission and Staff Initial Comments at 7; Pacific Northwest Utilities Initial Comments at 9; PJM Market Monitor Initial Comments at 5; Southern Initial Comments at 26.

[1710] Southern Initial Comments at 26 (citing Southern Initial Comments Ex. 1, ¶¶ 8, 15).

[1711] North Carolina Commission and Staff Initial Comments at 7.

[1712] Mississippi Commission Initial Comments at 36.

[1713] PJM Market Monitor Initial Comments at 5.

[1714] Pacific Northwest Utilities Initial Comments at 9.

[1715] *See* ACEG Initial Comments at 40; DC and MD Offices of People's Counsel Initial Comments at 25; GridLab Initial Comments at 26–27; MISO Initial Comments at 49–50.

[1716] NOPR, 179 FERC ¶ 61,028 at PP 200–201.

769. We note that Benefit 3 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 3 and Benefit 6, as described in this final order, both measure production cost savings (including savings that occur during generation outage contingencies), the system conditions used in calculating each benefit are distinct. For example, Benefit 6 can include higher electricity demand, forecast errors, volatile production costs, and a more expansive set of generation outages such as unplanned generation outages due to extreme weather. And as we discuss below in the context of Benefit 5, because Benefit 3, Production Cost Savings, as described in this order, does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well.

770. We also do not believe that requiring transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning will, as Southern suggests, result in double-counting of benefits because such benefits are also considered in state resource planning. While we acknowledge that integrated resource planning processes, where they exist, may consider similar benefits compared to those required by this final order, the consideration of benefits in a state-jurisdictional process does not result in the double-counting of benefits within any Commission-jurisdictional transmission planning process. Because practices affecting rates, terms, and conditions for interstate transmission service are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional regional transmission planning processes result in rates that are just and reasonable and not unduly or discriminatory. To this end, this final order is focused on ensuring that, when conducting Long-Term Regional Transmission Planning, transmission providers consider the broader set of benefits provided by Long-Term Regional Transmission Facilities so that they may determine whether to select such facilities as the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs.

771. Pacific Northwest Utilities assert that production cost savings are not easily quantifiable.[1717] We acknowledge that there are some challenges associated with measuring this benefit, but we conclude that it is nonetheless necessary to require such measurement in order to ensure that transmission rates are just, reasonable, and not unduly discriminatory or preferential. We also note that there is an abundance of examples of how transmission providers can measure this benefit. Production cost savings are used extensively in many transmission planning regions, including MISO, NYISO, PJM, SPP, CAISO, ISO–NE, NorthernGrid, and WestConnect.[1718] We believe that transmission providers are capable of measuring production cost savings given that this benefit has been used as a metric in transmission planning for decades.

772. In response to North Carolina Commission and Staff's contention that requiring consideration of production cost savings conflicts with state-jurisdictional resource decisions,[1719] we find that North Carolina Commission and Staff have failed to explain why there may be a conflict. As noted in the Need for Reform, there are deficiencies in the Commission's existing transmission planning and cost allocation requirements, including that they fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. We are concerned that failing to adequately identify and consider the benefits, including production cost benefits, of such transmission facilities may lead to relatively inefficient and less cost-effective transmission development. Additionally, as described above in the Categories of Factors section, transmission providers must incorporate, and not discount, state-jurisdictional resource decisions, such as integrated resource plans, into all Long-Term Scenarios to identify Long-Term Transmission Needs. Therefore, we believe that requiring transmission providers to measure production cost savings will not conflict with state-jurisdictional resource decisions, because the effects of such resource decisions on Long-Term Transmission Needs must be fully accounted for in all Long-Term Scenarios, which are used to help identify more efficient or cost-effective regional transmission solutions within the Commission-jurisdictional regional transmission planning process. Moreover, as discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section of this final order, nothing in this final order conflicts with or infringes on the states' reserved authority under FPA section 201.

773. We disagree with Mississippi Commission's assertion that production cost savings may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.[1720] Financial transmission rights are required in RTO/ISO markets and allow the market participant that owns the right to mitigate the congestion charge along an existing transmission path for the capacity of that path.[1721] A new transmission facility could reduce congestion and allow that market participant to purchase more electricity, exceeding the capacity of the transmission path for the financial transmission right, at a lower price. This reduced congestion allows for load to access lower cost resources, and results in more efficient dispatch of resources and, thus, provides avoided production cost benefits that are distinct from the avoided congestion charges associated with financial transmission rights.

774. We recognize the PJM Market Monitor's concern regarding the potential for inaccurate forecasts of key inputs to the calculation of production cost savings.[1722] However, we conclude that this potential concern does not outweigh the value of measuring and using this benefit, as demonstrated by long-standing use of this benefit within PJM and other transmission planning regions, including all RTOs/ISOs and some non-RTO/ISO regions. Moreover,

[1717] Pacific Northwest Utilities Initial Comments at 9.

[1718] *See* NOPR, 179 FERC ¶ 61,028 at PP 200–201; Brattle-Grid Strategies Oct. 2021 Report at 31; ISO New England, Inc., *Transmission Planning: Maintaining Power System Reliability Amid Change, https://www.iso-ne.com/system-planning/transmission-planning* (last visited Mar. 25, 2024); NorthernGrid, *Study Scope for the 2022–2023 NorthernGrid Planning Cycle,* 2 (Sept. 21, 2022), *https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf;* The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments,* 31 (July 2013), *https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf* (noting that in the Western Electricity Coordinating Council (WECC), whose service area includes one RTO (CAISO) and three non-RTO regions (ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect) production costs simulations are used to calculate the energy costs savings of transmission projects in WECC's long-term transmission planning studies).

[1719] North Carolina Commission and Staff Initial Comments at 7.

[1720] Mississippi Commission Initial Comments at 36.

[1721] *Long-Term Firm Transmission Rights in Organized Elec. Mkts.,* Order No. 681, 116 FERC ¶ 61,077, at PP 5, 19–21, *reh'g denied,* Order No. 681–A, 117 FERC ¶ 61,201 (2006), *order on reh'g & clarification,* Order No. 681–B, 126 FERC ¶ 61,254 (2009).

[1722] PJM Market Monitor Initial Comments at 5.

as noted in the Long-Term Scenarios section of this final order, the use of Long-Term Scenarios in Long-Term Regional Transmission Planning mitigates such uncertainty in transmission planning outcomes. Specifically, comparing the production cost savings, as well as the other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, provided by Long-Term Transmission Facilities across three distinct Long-Term Scenarios should help to address the uncertainty noted by the PJM Market Monitor.

iv. Benefit 4: Reduced Transmission Energy Losses

(a) NOPR Description

775. The Commission described this benefit in the NOPR as reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads.[1723]

776. The Commission explained that production cost savings metrics used today typically exclude reduced transmission energy losses and three other production cost savings-related benefits proposed in the NOPR. The Commission also stated that including those additional proposed benefits can produce a more robust set of congestion and production cost benefits that can be quantified and integrated into the method for calculating production cost savings and, therefore, help to ensure that more efficient or cost-effective transmission facilities are selected through Long-Term Regional Transmission Planning.[1724]

777. The Commission noted that to measure reduced transmission energy losses, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges. For example, ATC measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates using the marginal loss component from the PROMOD[1725] electric market simulation software simulations for the Paddock-Rockdale 345 kV Access Project,[1726] which produced cost reduction benefits using adjusted production cost analysis. Also, SPP's analysis for its Regional Cost Allocation Review process estimated energy loss reductions through post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.[1727]

(b) Comments

778. A number of commenters support mandating consideration of Benefit 4.[1728] While not favoring a benefits measurement requirement, Southern states that this benefit would likely prove workable under Southern's non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of reduced transmission energy losses.[1729]

779. Several commenters comment on the manner in which Benefit 4 should be calculated.[1730] ACEG states that this benefit has been calculated in various studies.[1731]

780. West Virginia Commission opposes the use of Benefit 4, arguing that the calculation of benefits from reduced transmission losses requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.[1732]

(c) Commission Determination

781. We adopt the NOPR proposal, with modification, to require transmission providers to measure and use Benefit 4, Reduced Transmission Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 4, as modified, as the reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads. We find that requiring the measurement and use of Benefit 4 in Long-Term Regional Transmission Planning is necessary because reduced energy losses are widely understood to be a benefit of transmission facilities.[1733] As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

782. We recognize that there are multiple ways for transmission providers to measure reduced transmission energy losses.[1734] We note that this final order does not require transmission providers to adopt any single method to measure reduced transmission energy losses. As described in the NOPR, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges.[1735] Transmission providers could also follow the example of ATC, which measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates provided by the PROMOD electric market simulation software.[1736]

[1723] NOPR, 179 FERC ¶ 61,028 at P 202.

[1724] *Id.* P 203.

[1725] PROMOD is a generator and portfolio modeling system. Hitachi Energy: PROMOD, *https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/enterprise/promod* (last visited Apr. 2024).

[1726] NOPR, 179 FERC ¶ 61,028 at P 204 & n.338 (citing ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 34–38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007)).

[1727] SPP, *SPP Regional Cost Allocation Review Report for RCAR II,* at 56, 64 (July 11, 2016), *https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.*

[1728] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 13–14; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1729] Southern Initial Comments at 25.

[1730] ACEG Initial Comments at 41; NARUC Initial Comments at 23 (noting that advanced technologies also provide this benefit and should be preferred over greenfield construction); Utah Division of Public Utilities Initial Comments at 8.

[1731] ACEG Initial Comments at 41 (citing ATC, Planning Analysis of the Paddock-Rockdale Project, app. C Ex. 1, at 34–38 (Wisc. Pub. Serv. Docket No. 137–CE–149); SPP, *Regional Cost Allocation Review Report for RCAR II,* at 5 (July 11, 2016), *https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf*).

[1732] West Virginia Commission Supplemental Comments at 4.

[1733] *See* Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11–14; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1734] *See, e.g.,* ACEG Initial Comments at 41 (citing studies in which Benefit 4 has been calculated).

[1735] NOPR, 179 FERC ¶ 61,028 at P 204.

[1736] ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C

Similarly, SPP estimates energy loss reductions through its Regional Cost Allocation Review process by post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.[1737]

783. Because we find that transmission providers have multiple ways of calculating the benefit of reduced transmission energy losses, as well as record evidence demonstrating that the calculation of Benefit 4 is either already considered or is feasible in multiple transmission planning regions, we disagree with West Virginia Commission's claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.[1738] We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.[1739]

v. Benefit 5: Reduced Congestion Due to Transmission Outages

(a) NOPR Description

784. The Commission described Benefit 5 in the NOPR as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect transmission outages, planned or unplanned.[1740] The Commission noted that transmission providers could measure this benefit, for example, by either building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by inducing system constraints more frequently. One application of this approach is SPP's Regional Cost Allocation Review process, which, inter alia, measured the benefits of reducing congestion resulting from transmission outages. In this process, SPP modeled outage events and new constraints based on these outages in PROMOD for a 2025 case year, and then conducted PROMOD simulations to calculate adjusted production cost savings for a base case and the change case including the transmission line.[1741]

(b) Comments

785. A number of commenters support mandating consideration of Benefit 5.[1742] While Southern does not support a requirement to use this or other benefits, it states that this benefit—which Southern understands as ''operational flexibility''—could be explored for potential adoption in its footprint.[1743]

786. A few commenters opine on how to calculate the benefit of reduced congestion due to transmission outages.[1744] ACEG states that most transmission planning models ignore unplanned transmission outages that are likely to occur during extreme weather events, which ACEG claims will underestimate the value of Benefit 5.[1745] Similarly, DC and MD Offices of People's Counsel argue that, because unplanned transmission outages cause a significant portion of congestion costs, calculation of this benefit should account for such outages.[1746]

787. Some commenters oppose mandating consideration of Benefit 5.[1747] AEP argues that reduced congestion due to transmission outages is of lesser importance and does not need to be in the required minimum set of benefits.[1748] NARUC states that benefits associated with new construction to alleviate congestion is already a planning consideration.[1749] Pacific Northwest Utilities and West Virginia Commission assert that this benefit is not easily quantifiable.[1750] Idaho Power states that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion.[1751]

(c) Commission Determination

788. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 5, Reduced Congestion Due to Transmission Outages, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 5 as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. We find that requiring the measurement and use of Benefit 5, as described, is necessary because reduced congestion due to transmission outages is widely understood to be a benefit of transmission facilities.[1752] As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional

Ex. 1, at 34–38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[1737] SPP, *Regional Cost Allocation Review Report for RCAR II,* at 56, 64 (July 11, 2016), *https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.*

[1738] West Virginia Commission Supplemental Comments at 4.

[1739] *PacifiCorp,* 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

[1740] NOPR, 179 FERC ¶ 61,028 at P 205 & n.340 (citing Brattle-Grid Strategies Oct. 2021 Report at 79).

[1741] *Id.* P 205 & n.341 (citing SPP, Inc., *Regional Cost Allocation Review Report for RCAR II,* at 51–52 (July 11, 2016), *https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.* To estimate incremental savings associated with mitigation of transmission outage costs, SPP analyzed outage cases in PROMOD for the 2025 study year. SPP developed cases based on 12 months of historical SPP transmission data. SPP said that because of the high volume of historical transmission outage data (approximately 7,000 outage events) and based on the expectation that many outages would not lead to significant increases in congestion, SPP only modeled a subset of outage events. The events selected were those expected to create significant congestion and met at least one of three conditions. *Id.* at 51.)

[1742] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

[1743] Southern Initial Comments at 25.

[1744] ACEG Initial Comments at 41–42; DC and MD Offices of People's Counsel Initial Comments at 25–26.

[1745] ACEG Initial Comments at 41.

[1746] DC and MD Offices of People's Counsel Initial Comments at 25–26.

[1747] AEP Initial Comments at 27–28; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1748] AEP Initial Comments at 27.

[1749] NARUC Initial Comments at 23.

[1750] Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1751] Idaho Power Initial Comments at 8.

[1752] *See* Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

transmission solutions to address Long-Term Transmission Needs.

789. We also find that consideration of Benefit 5 is necessary because most current production cost simulations only consider generation outages—both planned generation outages and random distributions of unplanned generation outages; by contrast, production cost simulations do not typically address transmission outages, either planned or unplanned. Given that transmission facilities can provide benefits by reducing production costs during both generation outages and transmission outages, we find that it is necessary for transmission providers to measure and use production cost savings during both generation outages and transmission outages in Long-Term Regional Transmission Planning. Because Benefit 3, Production Cost Savings, as described in this order does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 5 and Benefit 6 both measure the benefit of reduced congestion due to transmission outages, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages such as unplanned outages due to extreme weather.

790. For the reasons stated above, we disagree with AEP's arguments that reduced congestion due to transmission outages is less important than other benefits and thus should not be required.[1753] And while some commenters object to consideration of reduced congestion due to transmission outages as a benefit on the grounds that this benefit is not easily quantifiable,[1754] we believe this benefit is merely another variant in production cost savings modeling that we already require for other benefits, such as Benefits 3 and 4.

vi. Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions

(a) NOPR Description

791. The Commission described the benefit of mitigation of extreme events and system contingencies in the NOPR as reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies.[1755] These benefits include reduced production costs during extreme events facilitated by a more robust transmission system that reduces high-cost generation and emergency procurements necessary to support the system.[1756] The Commission noted that transmission providers can measure benefits from the mitigation of extreme events and system contingencies by calculating the probability-weighted production cost savings through production cost simulation for a set of extreme historical market conditions. The Commission provided as one example CAISO's analysis of Devers-Palo Verde Line No. 2, where CAISO modeled several contingencies to determine the value of the line during high-impact, low-probability events and, as another example, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line. ATC found that probability-weighted savings from reducing production and power purchase costs during a number of simulated extreme events offset 20% of total project costs.[1757] The Commission also noted that a study found development of an additional 1,000 MW of transmission capacity into Texas would have fully paid for itself over four days during Winter Storm Uri and the same into MISO would have saved $100 million during the same time period.[1758]

792. Separately, the Commission described the benefit of mitigation of weather and load uncertainty in the NOPR as reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.[1759] The Commission stated that this is beyond the effects of extreme weather described above and may account for, for example, regional and sub-regional load variances that will occur due to changing weather patterns.[1760] The Commission provided, as one example, simulations that ERCOT performed for normal loads, higher-than-normal loads, and lower-than-normal loads for a Houston import project, which showed increased benefits with a probability-weighted average for all three simulated load conditions.[1761]

(b) Comments

793. A number of commenters support mandating consideration of the benefit of mitigation of extreme events and system contingencies.[1762] For instance, Grid United states that extreme weather conditions significantly affect the electric grid and that requiring transmission providers to consider transmission projects based on their ability to mitigate extreme weather events will enhance resilience.[1763] ACEG and DC and Maryland Offices of People's Counsel state that consideration of the benefit of mitigation of extreme events and system contingencies is merited given ''the hundreds of millions of dollars that would have been saved if transmission capacity had been greater during a number of actual severe weather episodes.'' [1764] Clean Energy Associations assert that transmission providers should not calculate benefits

[1753] AEP Initial Comments at 27.

[1754] *See* Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1755] NOPR, 179 FERC ¶ 61,028 at P 206.

[1756] *Id.*

[1757] *Id.* P 207 & n.342 (*Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338–E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project,* Application 05–04–015 (Cal. Comm'n Jan. 27, 2007)) & n.343 (ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 4, 50–53 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007)).

[1758] *Id.* P 207 & n.344 (M. Goggin, Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2020)).

[1759] *Id.* P 208.

[1760] *Id.*

[1761] *Id.* P 209 & n.345 (citing ERCOT, *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting,* at 10 (Mar. 4, 2011). The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios).

[1762] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; ACORE Supplemental Comments at 1; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94 (in combination with Benefit 7, noting that significant stakeholder engagement is needed to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32; US Senator Schumer Supplemental Comments at 2–3.

[1763] Grid United Initial Comments at 3.

[1764] ACEG Initial Comments at 43 & n.119; DC and Maryland Offices of People's Counsel Initial Comments at 26–27 & n.65 (both citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (Jul. 2021), *https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf*).

solely based on average system conditions, as transmission investments can provide significant benefits during abnormal or extreme conditions or events.[1765]

794. Some commenters comment on the manner in which the benefit of mitigation of extreme events and system contingencies should be calculated.[1766] ACEG states that the benefit of mitigation of extreme events and system contingencies can be calculated by retrospective analysis or probabilistically. Additionally, ACEG recommends that the Commission require transmission providers to include avoided scarcity pricing, storm hardening and wildfire resilience, grid strength, and increased fuel diversity and system flexibility in addition to production cost savings when calculating the benefit of mitigation of extreme events and system contingencies.[1767] Similarly, DC and MD Offices of People's Counsel assert that the benefit of mitigation of extreme events and system contingencies should include resilience benefits such as storm and wildfire hardening, fuel diversity, and system flexibility, as well as reduced prices to consumers given that many regions set scarcity prices at values higher than generator production costs.[1768]

795. A number of commenters also support mandating consideration of the benefit of mitigation of weather and load uncertainty.[1769] Some commenters comment on the manner in which the benefit of mitigation of weather and load uncertainty should be calculated.[1770] GridLab posits that mitigation of weather and load uncertainty should only be included in the context of planning and operating reserves because ''the cost to system operators of mitigating uncertainty is [the same as] the cost of holding additional reserves.'' [1771]

796. Other commenters oppose mandating consideration of the benefit of mitigation of extreme events and system contingencies, arguing that it is challenging to quantify and that its calculation entails subjective judgment.[1772] Louisiana Commission states that the value of mitigating extreme weather events can vary significantly across transmission planning regions and states. Louisiana Commission opposes any extreme weather benefit category that would result in the assignment of costs of transmission hardening projects to Louisiana ratepayers from which they do not benefit. Louisiana Commission further states that any analysis of this benefit should be limited to sensitivities.[1773]

797. Some commenters oppose mandating consideration of the mitigation of weather and load uncertainty.[1774] AEP states that this benefit should not be included in the minimum set of benefits because it is of lesser importance than other benefits described in the NOPR.[1775] NRECA argues that quantifying this benefit requires subjective judgment.[1776] According to Pacific Northwest Utilities, this benefit accrues to generation and load-serving entities, not to transmission providers.[1777]

798. NARUC states that the benefits of mitigation of extreme events, system contingencies, weather, and load uncertainties may be more appropriate for consideration in interregional transmission planning, depending on the size of the transmission planning region. While NARUC states that mitigation of such contingencies is among the soundest reasons for Interregional Transfer Capability planning, it also notes that in regions with a large footprint (*e.g.,* PJM, MISO) it may be possible to assess these resilience benefits in the regional transmission planning process.[1778]

799. MISO states that the treatment of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty as economic benefits differ only to the degree at which production cost savings are realized. MISO also states that ''mitigation of extreme events'' may be represented as a reliability benefit where a value of outage costs can be used to monetize the benefits of mitigating the risk of load shedding.[1779] PJM suggests that the Commission should consolidate the benefits of mitigation of extreme events and system contingencies and the benefits of mitigation of weather and load uncertainty into a single enhanced reliability benefit that would evaluate the ability of grid enhancements to serve load reliably under extreme events and vulnerabilities.[1780] MISO and NARUC state that their comments regarding mitigation of extreme events and system contingencies are equally applicable to mitigation of weather and load uncertainty.[1781]

(c) Commission Determination

800. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Order Benefit 6, mitigation of extreme weather events and unexpected system conditions, in Long-Term Regional Transmission Planning. The revised Final Order Benefit 6 modifies and combines two of the benefits proposed in the NOPR: (1) mitigation of extreme events and system contingencies (NOPR Benefit 6) and (2) mitigation of weather and load uncertainty (NOPR Benefit 7).[1782] In combining these two proposed NOPR benefits, we modify the description of NOPR Benefit 6 and describe Final Order Benefit 6 as reduced production costs and reduced loss of load (or emergency procurements necessary to support the system), including due to increased Interregional Transfer Capability, during extreme weather events and unexpected system conditions, such as unusual weather conditions or fuel shortages that result in multiple concurrent and sustained generation and/or transmission outages. The description of Final Order Benefit 6 that we adopt in this final order

[1765] Clean Energy Associations Initial Comments at 21.

[1766] ACEG Initial Comments at 43; Clean Energy Associations Initial Comments at 21; DC and MD Offices of People's Counsel Initial Comments at 26–27; MISO Initial Comments at 51; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9.

[1767] ACEG Initial Comments at 43–44.

[1768] DC and MD Offices of People's Counsel Initial Comments at 26–27.

[1769] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94 (in combination with Benefit 6, noting that significant stakeholder engagement would be necessary to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

[1770] ACEG Initial Comments at 44; GridLab Initial Comments at 26; NARUC Initial Comments at 23.

[1771] GridLab Initial Comments at 26.

[1772] NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1773] Louisiana Commission Initial Comments at 18–19.

[1774] AEP Initial Comments at 27; NARUC Initial Comments at 23; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9.

[1775] AEP Initial Comments at 27.

[1776] NRECA Initial Comments at 45.

[1777] Pacific Northwest Utilities Initial Comments at 9.

[1778] NARUC Initial Comments at 21, 23.

[1779] MISO Initial Comments at 51.

[1780] PJM Initial Comments at 94.

[1781] MISO Initial Comments at 51; NARUC Initial Comments at 23.

[1782] NOPR, 179 FERC ¶ 61,028 at PP 206–207 (NOPR Benefit 6), 208–209 (NOPR Benefit 7).

includes three additional modifications to the NOPR proposals describing NOPR Benefit 6 and NOPR Benefit 7. First, we require transmission providers to measure, as part of Benefit 6,[1783] the benefits of reduced loss of load (not only reduced production costs). Second, we require transmission providers, as part of Benefit 6, to account for both extreme weather events and unexpected system conditions when transmission facilities have particularly high value. The unexpected system conditions can include, for example, system contingencies in the form of generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors. Third, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility during an extreme weather event or unexpected system condition that results in multiple and concurrent sustained generation and/or transmission outages.

801. We find that requiring the measurement and use of Benefit 6 in Long-Term Regional Transmission Planning is necessary because Long-Term Regional Transmission Facilities could result in reduced production costs and reduced loss of load (or reduced emergency procurements necessary to support the system), including reductions due to increased Interregional Transfer Capability, and improved performance during extreme weather events and unexpected system conditions. Further, the benefit of mitigation of high production costs resulting from extreme weather events and unexpected system conditions can be economically significant. A relatively few numbers of hours could represent a large share of the total benefit of reduced congestion costs that a Long-Term Regional Transmission Facility provides.[1784] We also find that it is critical for transmission providers to measure and use Benefit 6 given that extreme weather events and unexpected system conditions have significantly and increasingly affected the reliable operation of the electric grid. As the Commission has previously noted, extreme weather events have occurred with greater frequency in recent years, leading to load shed events that present an unacceptable risk to life and have an extreme economic impact.[1785] By requiring the use of Benefit 6, we ensure that transmission providers measure and use the benefit of Long-Term Regional Transmission Facilities under these conditions when performing Long Term Regional Transmission Planning. Further, by requiring use of Benefit 6, we enable transmission providers to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

802. Regarding the first modification listed above, we require transmission providers to measure, as part of Benefit 6, reduced loss of load (or reduced emergency energy procurement to avoid loss of load), not only reduced production costs. We find it necessary to include reduced loss of load because Long-Term Regional Transmission Facilities can provide benefits by improving reliability during extreme weather events and unexpected system conditions,[1786] which can be significant given the high cost and risk to life during periods with insufficient generation to meet system load. An example of how a reduction in loss of load could be measured is by quantifying the reduction in expected unserved energy but for the Long-Term Regional Transmission Facility during an extreme weather event or unexpected system conditions, determining the value of lost load, and multiplying these two values to obtain a monetary value.[1787]

803. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use, because transmission providers must model different system conditions (extreme weather events and unexpected system conditions) when measuring Benefit 6. Specifically, Benefit 2(a) measures reduced loss of load probability in the context of the system conditions used for resource adequacy planning, which typically includes consideration of normal system conditions and may vary by region. In contrast, Benefit 6 measures reduced loss of load for specific extreme weather events and unexpected system conditions identified by the transmission providers.[1788] Additionally, while Benefit 3 and Benefit 6 both measure production cost savings, the system conditions used to measure Benefit 6 can include higher electricity demand, volatile production costs, and a more expansive set of generation outages, such as unplanned generation outages due to extreme weather. Similarly, Benefit 5 and Benefit 6 both measure the benefits of reduced congestion due to transmission outages; however, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages, such as unplanned transmission outages due to extreme weather.

804. Regarding the second modification listed above, we require transmission providers, as part of Benefit 6, to account for mitigation of unexpected system conditions during periods when transmission facilities have particularly high value, not only during extreme weather events. We recognize that unexpected system conditions can create periods when Long-Term Regional Transmission Facilities have particularly high value because of, for example, generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors.[1789] Limited resource availability, or limited system flexibility, can make

[1783] Throughout this final order, ''Benefit 6'' refers to ''Final Order Benefit 6'' unless preceded by ''NOPR.''

[1784] *E.g.,* ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[1785] *See* Order No. 896, 183 FERC ¶ 61,191 at P 2; Order No. 897, 183 FERC ¶ 61,192 at PP 21–22.

[1786] PJM Initial Comments at 94; MISO Initial Comments at 12–13; Order No. 897, 183 FERC ¶ 61,192 at PP 6–12.

[1787] *E.g.,* MISO, *LRTP Tranche 2 Business Case Benefit Metrics,* 6–7 (Aug. 31, 2023), *https://cdn.misoenergy.org/20230831%20LRTP%20Workshop%20Item%2002%20Business%20Case%20Metrics%20Development630034.pdf.*

[1788] Benefit 2(b), which measures the benefit of reduced planning reserve margin, is also used in the context of resource adequacy planning. We do not allow transmission providers to measure Benefit 6 in terms of reduced planning reserve margin because system planners do not always model extreme weather events or unexpected system conditions when establishing the planning reserve margin used for resource adequacy purposes. In contrast, reduced loss of load can be measured for any system condition, even those conditions that are not used for resource adequacy planning.

[1789] *See, e.g.,* ACEG Initial Comments at 42–45 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System* (Oct. 14, 2020), *https://open.bu.edu/handle/2144/41451*; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* 2, 34, 78, 85–86, 99 (2021), *https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-TransmissionPlanning-Report_v2.pdf*); DC and MD Offices of People's Counsel Initial Comments at 28 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System, BU–ISE* (Oct. 14, 2020), *https://open.bu.edu/handle/2144/41451*); US Senator Schumer Supplemental Comments at 2–3 (citing Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade,* 3–6 (Feb. 2023), *https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf*); US Senator Whitehouse Supplemental Comments at 2 (referencing outages related to extreme events having costs, including economic costs of in the billions of dollars from elevated energy costs).

it challenging for system operators to immediately address these unexpected system conditions, and Long-Term Regional Transmission Facilities that provide benefits under Benefit 6 will equip system operators with more options to manage the worst-case outcomes. These high-value periods of unexpected system conditions, while infrequent and not necessarily during extreme weather events, may account for a large share of the potential value of a Long-Term Regional Transmission Facility.[1790] We require transmission providers to account for circumstances that contribute to these infrequent and high-value periods specific to their transmission planning region when measuring Benefit 6. Transmission providers may, for example, identify historical periods when significant transmission congestion was due to certain conditions (*e.g.,* generators being unavailable due to a forecast error), then model those conditions in each Long-Term Scenario.[1791] Therefore, we require transmission providers to use not only information from modeling extreme weather events but also information from additional modeling that accounts for unexpected system conditions, as part of Benefit 6. To avoid double-counting of similar circumstances, transmission providers must account for extreme weather events and unexpected system conditions that are separate and distinct such that the benefits of mitigating each system condition can be combined into a single benefit measure.

805. Finally, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages. As discussed above, we find that Long-Term Regional Transmission Facilities can increase Interregional Transfer Capability by changing the topology of the transmission system.[1792] Further, we find that the benefits of mitigating extreme weather events and unexpected system conditions due to increased Interregional Transfer Capability provided by Long-Term Regional Transmission Facilities can be significant.[1793] To comply with this requirement, transmission providers must include in the modeling they use to measure Benefit 6 any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages.

806. To account for extreme weather events as part of Benefit 6, transmission providers may incorporate information from the sensitivity they must develop and apply to each Long-Term Scenario that includes multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.[1794] We reiterate that we require transmission providers to measure the required benefits under each Long-Term Scenario. However, in the case of Benefit 6, transmission providers may measure the benefit of mitigating extreme weather events using the required extreme weather event sensitivity applied to each Long-Term Scenario; we do not require them to separately measure the benefit of mitigating extreme weather events in each scenario without applying that sensitivity.[1795]

807. Consistent with all other benefits that we require transmission providers to measure, we do not require a standardized method for measuring Benefit 6 subject to measuring the components described above.[1796] As the Commission stated in the NOPR, there are different approaches to calculating components of this benefit,[1797] and this final order provides transmission providers with flexibility in developing the method that they will use to measure this benefit.

808. We disagree with commenters who express general concerns regarding the difficulty of measuring this benefit.[1798] In the NOPR, the Commission identified studies that measured benefits of a transmission facility in a manner similar to the requirements in Benefit 6.[1799] Because we allow flexibility as far as the method transmission providers use to measure each benefit included in the required set of benefits, including Benefit 6, we believe that transmission providers should be able to tailor a method for measuring Benefit 6 that fits their circumstances. Further, transmission providers can build on methods that they use to measure the other benefits required by this final order to measure Benefit 6. For example, transmission providers can use the same method to measure reduced production costs in accordance with Benefit 6 as they do to measure Benefit 3, Production Costs Savings, but modify the model inputs to capture reduced production costs during extreme weather events and unexpected system conditions. Moreover, we recognize that there is a balance between requiring transmission providers to measure the benefits of Long-Term Regional Transmission Facilities that are most readily measured and ensuring that transmission providers are appropriately capturing the value of Long-Term Regional Transmission Facilities when evaluating them for selection. Even to the extent to which Benefit 6 may be more difficult to measure than the other benefits that

[1790] LBNL Aug. 2022 Transmission Value Study at 33 (stating that the majority of transmission value estimated occurs during ''extreme'' conditions that fall outside of the 171 designated extreme weather event days between 2012 and 2021); Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade,* 3–6 (Feb. 2023), *https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf.*

[1791] Alternatively, transmission providers may, for example, use probabilistic transmission planning methods to account for infrequent and high-value periods.

[1792] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section.

[1793] ACEG Initial Comments at 5; ACEG Reply Comments at 3–5; BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 5, 21; Kansas Corporation Commission Initial Comments at 8–9; NARUC Initial Comments at 23; US DOE Initial Comments at 39–42.

[1794] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section (stating transmission providers must develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area). Transmission providers may also incorporate analyses from an Extreme Weather Vulnerability Assessment as generally described in Order No. 897.

[1795] We recognize that transmission providers may not use an extreme weather event sensitivity that includes system conditions that allow transmission providers to measure the benefit of mitigating unexpected system conditions in every Long-Term Scenario. In such cases, transmission providers must measure the benefit of mitigating unexpected system conditions in each Long-Term Scenario even without an extreme weather event sensitivity applied to those scenarios or must apply a separate sensitivity that allows for the measurement of Benefit 6 to each Long-Term Scenario.

[1796] *E.g.,* ACEG Initial Comments at 42–44; DC and MD Offices of People's Counsel Initial Comments at 26–27.

[1797] NOPR, 179 FERC ¶ 61,028 at P 207 (providing examples of CAISO's analysis of Devers-Palo Verde Line No. 2, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line, and a Grid Strategies study).

[1798] NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

[1799] NOPR, 179 FERC ¶ 61,028 at PP 207, 209.

we require, we nonetheless find that requiring transmission providers to measure Benefit 6 is necessary because Benefit 6 is significant.[1800]

809. We are unpersuaded by general arguments that transmission providers should not consider this benefit because it varies by transmission planning region or it only accrues to certain entities.[1801] We are not requiring transmission providers to model a specific extreme weather event or unexpected system condition; transmission providers may decide what extreme weather event and unexpected system conditions to model, allowing them to ensure that the conditions modeled are relevant to circumstances in their transmission planning region. In response to NRECA's argument that this benefit requires subjective judgement,[1802] we conclude that transmission providers have sufficient expertise to identify and model extreme weather events and unexpected system conditions when evaluating Long-Term Regional Transmission Facilities.[1803] In response to AEP's argument that NOPR Benefit 7 (mitigation of weather and load uncertainty) is of lesser importance compared to other benefits described in the NOPR and should be optional for transmission providers to measure and use,[1804] we disagree because the evidence in the record demonstrates that Final Order Benefit 6 (which includes NOPR Benefit 7) is significant.[1805]

810. NARUC states that the benefit of mitigation of extreme weather events may need to be more fully considered only in large transmission planning regions or in interregional transmission planning.[1806] Although transmission providers could also consider the benefits of mitigation of extreme weather events as part of interregional transmission coordination, we believe transmission providers can measure and use the benefit of mitigation of extreme weather events in regional transmission planning processes regardless of the size of the transmission planning region, because extreme weather events can occur and affect the transmission system in any region. If the size of the extreme weather event is larger than the transmission planning region, transmission providers can consider the extent to which they can rely on interregional flows from other transmission planning regions during the extreme weather event. We note that transmission providers in each transmission planning region must coordinate and share information with the transmission providers in each neighboring transmission planning region and must identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs, as described in more detail in the Interregional Transmission Coordination section of this final order. Better measurement of the benefits of mitigation of extreme weather events as part of regional transmission planning can only help facilitate such efforts. We encourage transmission providers in neighboring transmission planning regions to share information with one another that would be useful to measure Benefit 6 more accurately through their interregional transmission coordination procedures.

811. Some commenters state that the benefits of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty overlap, or should be combined.[1807] We note that Benefit 6, as described above, modifies and combines the benefits proposed in the NOPR of (1) mitigation of extreme events and system contingencies and (2) mitigation of weather and load uncertainty, which should address concerns of separately requiring transmission providers to use two similar benefits that some argue could overlap.

vii. Final Order Benefit 7: Capacity Cost Benefits From Reduced Peak Energy Losses

(a) NOPR Description

812. The Commission described this benefit, NOPR Benefit 8 (renumbered in this final order as Final Order Benefit 7), in the NOPR as reduced generation capacity investment needed to meet peak load.[1808] The Commission noted that capacity cost savings from reduced peak energy losses benefits refer to the ability of proposed transmission facilities to lessen the amount of transmission system energy losses during peak-load conditions which, over time, would decrease the need for new generation capacity installations or purchases. To the extent that new transmission facilities result in changes to generation dispatch and flows, transmission system energy losses will also change. If transmission system losses are reduced via the new transmission facilities, transmission providers will not have to construct or procure additional generation to satisfy installed capacity requirements for peak-load conditions. If there is a reduction in energy losses during peak conditions, this would result in, presumably, lowered investments for generation capacity resources to meet the peak load. For example, Entergy found that potential transmission facilities in its footprint could reduce peak-load transmission losses and associated needed generation investment by 2% of total transmission facility costs.[1809] The Commission noted that capacity cost savings from reduced peak energy losses only attempt to evaluate benefits for peak-load conditions.

813. The Commission stated that one potential way to calculate capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements.[1810] To arrive at the value of associated capital cost savings, the estimated net cost of new entry (Net CONE) (*i.e.,* the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) would be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions that would be passed on to consumers via lowered generation capacity costs.[1811]

(b) Comments

814. A number of commenters support mandating consideration of NOPR Benefit 8.[1812] ACEG and DC and

[1800] *Supra* P 797.

[1801] Louisiana Commission Initial Comments at 18–19; Pacific Northwest Utilities Initial Comments at 9.

[1802] NRECA Initial Comments at 45.

[1803] NESCOE Initial Comments at 42.

[1804] AEP Initial Comments at 27.

[1805] *Supra* note 1769; *see also* ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[1806] NARUC Initial Comments at 21, 23.

[1807] MISO Initial Comments at 51; PJM Initial Comments at 94.

[1808] NOPR, 179 FERC ¶ 61,028 at P 210.

[1809] *Id.* P 211 & n.346 (citing ITC, Joint Application, Docket No. EC12–145–000, Ex. ITC–600 (Testimony of Pfeifenberger), at 77–78 (filed Sept. 24, 2012)).

[1810] *Id.* P 212.

[1811] *Id.*

[1812] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32, 45; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

MD People's Counsel state that NOPR Benefit 8 is a distinct benefit category that has been measured before.[1813] PIOs state that SPP quantified NOPR Benefit 8 in its 2016 Regional Cost Allocation Review and that ''leav[ing] these cost savings on the cutting room floor will ultimately raise costs for consumers and result in an inefficient transmission plan.'' [1814]

815. Other commenters, such as NARUC, oppose mandating consideration of NOPR Benefit 8. NARUC contends that this benefit is a subset of the lowered system reserve margins benefit. NARUC states that NOPR Benefit 8 is unlikely to occur within organized, competitive generation markets because additional transmission will not deter the installation of new generation under current Federal open access policies. However, NARUC argues, this benefit may be attainable in transmission planning regions served by vertically integrated utilities where transmission can substitute for new generation construction. NARUC asserts that hundreds of thousands of megawatts of generation currently await interconnection studies in the various RTOs/ISOs and non-RTO/ISO transmission planning regions, and it is difficult to see how construction of new transmission facilities can remove any of this demand for additional generator interconnection.[1815]

816. West Virginia Commission also opposes a requirement to use NOPR Benefit 8, arguing that the calculation requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.[1816]

(c) Commission Determination

817. As an initial matter, we renumber NOPR Benefit 8 and refer to it in this determination section as Final Order Benefit 7. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Order Benefit 7, Capacity Cost Benefits from Reduced Peak Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Final Order Benefit 7 as reduced generation capacity investment needed to meet peak load.[1817] We find that requiring the use and measurement of Final Order Benefit 7, as described, is necessary to ensure that capacity cost benefits from reduced peak energy losses are not excluded from Long-Term Regional Transmission Planning because standard production cost modeling and the other benefits that this final order requires transmission providers to measure and use will not capture this benefit. Absent a requirement for transmission providers to measure and use Final Order Benefit 7 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

818. One potential way to measure capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements. To arrive at the value of capital cost savings, the estimated net cost of new entry (*i.e.,* the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) could be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions, savings that would be passed on to customers via lowered generation capacity costs.

819. We disagree with NARUC's contention that this benefit is a subset of the lowered system reserve margins benefit and that it is unlikely to occur within organized, competitive generation markets.[1818] ACEG and DC and MD People's Counsel both indicate that Final Order Benefit 7 is a distinct benefit category that has been measured before, citing MISO's Multi-Value Project portfolio, among other examples of its use, which measures capacity cost savings from reduced peak energy losses as an independent benefit.[1819] While we acknowledge that this benefit may have the effect of lowering system reserve margins, we agree with PIOs that these cost savings are distinct from Benefit 2 and that failing to specifically evaluate potential cost savings related to reduced peak energy losses may result in higher capacity costs and relatively inefficient or less cost-effective transmission development. As discussed above, Benefit 2 recognizes potential cost savings of providing additional pathways for connecting generation resources with load. Here, we are assessing the benefits of limiting transmission losses along those pathways. We also note that this approach is consistent with Benefits 3 and 4 above that separately recognize potential cost savings associated with lower production costs and reduced transmission energy losses in energy markets. In light of the evidence that multiple transmission providers have successfully measured this benefit, as well as the example that we provide above describing how a transmission provider may be able to calculate this benefit, we further disagree with West Virginia Commission's argument that calculation of this benefit is based on assumptions that are difficult to quantify in advance.

viii. Other Benefits

(a) Comments

820. Numerous commenters address in various ways the other five benefits that the Commission described in the NOPR but that we do not require transmission providers to measure and use in Long-Term Regional Transmission Planning in this final order: mitigation of weather and load uncertainty,[1820] deferred generation capacity investments, access to lower cost generation, increased competition, and increased market liquidity.[1821]

[1813] ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12–145–000, Ex. ITC–600 (Testimony of Pfeifenberger), at 77–78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137–CE–149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

[1814] PIOs Initial Comments at 42.

[1815] NARUC Initial Comments at 24.

[1816] West Virginia Commission Supplemental Comments at 4.

[1817] We note that in the NOPR, this benefit was designated as Benefit 8. We have revised the ordering designation of this benefit in this final order.

[1818] NARUC Initial Comments at 24.

[1819] ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12–145–000, Ex. ITC–600 (Testimony of Pfeifenberger), at 77–78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137–CE–149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

[1820] We note that elements of this benefit are now contained in Benefit 6, the description of which has been revised from the NOPR.

[1821] Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32, 45–48; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25–27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20, 28–30; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Idaho Power Initial Comments at 7–8; Interwest Initial

Continued

Other commenters address in various ways benefits not listed in the NOPR for transmission providers to consider for use in evaluating Long-Term Regional Transmission Facilities.[1822]

(b) Commission Determination

821. We decline to require transmission providers to measure and use the remaining five benefits described in the NOPR in Long-Term Regional Transmission Planning (*i.e.,* mitigation of weather and load uncertainty, generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity). We find that the required set of benefits that we adopt herein is a sufficiently broad range of benefits to ensure that transmission providers are identifying, evaluating, and selecting Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. As such, we find that the measurement and use of additional benefits in Long-Term Regional Transmission Planning is not necessary to ensure that rates remain just and reasonable.

822. However, we recognize that Long-Term Regional Transmission Facilities may provide additional benefits that may merit consideration when transmission providers are identifying, evaluating, and selecting such facilities to address Long-Term Transmission Needs more efficiently or cost-effectively. Therefore, transmission providers may measure and use additional benefits beyond those included in the required set of benefits in Long-Term Regional Transmission Planning, including on a transmission facility or plan-specific basis, subject to the requirement that they do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.

3. Identification, Measurement, and Evaluation of the Benefits of Long-Term Regional Transmission Facilities

a. NOPR Proposal

823. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits that they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers would be required to explain the rationale for using the benefits identified.[1823]

b. Comments

824. Many commenters support requiring identification of, and transparency regarding, the benefits that transmission providers will use in Long-Term Regional Transmission Planning.[1824] For example, Nebraska Commission states that the NOPR proposal will foster the necessary flexibility to accommodate varying needs and approaches of different transmission planning regions.[1825]

825. Certain TDUs and Michigan Commission state that transmission providers must clearly articulate their methods for calculating identified benefits.[1826] Certain TDUs further state that benefits should be evaluated with consistent reference cases to ensure consistency across scenarios.[1827] Certain TDUs and Entergy state that transmission providers should incorporate their benefit calculation methods, as well as, according to Entergy, their role in selection, into the OATT.[1828] Entergy argues that the Commission should allow transmission providers to use different benefits on a regional or subregional level, but that benefits should not change from one transmission project or portfolio to the next without an OATT amendment.[1829]

826. MISO TOs state that MISO already meets the NOPR's proposed requirement to identify benefits used in Long-Term Regional Transmission Planning and explain how they will be calculated.[1830]

827. Some commenters express concerns with the Commission's proposed benefit identification requirement,[1831] including concerns over perceived excessive quantification [1832] or requirements to calculate benefits individually.[1833] Duke asserts that the Commission should

Comments at 12–14; ISO–NE Initial Comments at 34; Joint Consumer Advocates Initial Comments at 11–12; MISO Initial Comments at 50–51; NARUC Initial Comments at 21, 24–25; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11–14; North Carolina Commission and Staff Initial Comments at 6–7; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94; PJM Market Monitor Initial Comments at 5–6; PPL Initial Comments at 13–15; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; Southern Initial Comments at 25–27; West Virginia Commission Supplemental Comments at 4; US DOE Initial Comments at 31–32.

[1822] ACEG Initial Comments at 6–8; AEE Reply Comments at 25–26; AEP Initial Comments at 6, 23–27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–23; California Commission Initial Comments at 31–34; California Energy Commission Initial Comments at 3; CARE Coalition Initial Comments at 32–33; Certain TDUs Reply Comments at 1–3; Clean Energy Associations Initial Comments at 19–20; Clean Energy Buyers Initial Comments at 20–21; Clean Energy States Initial Comments at 6–8; DC and MD Offices of People's Counsel Initial Comments at 18–19; Entergy Initial Comments at 21; Environmental Groups Supplemental Comments at 2–3; Grand Rapids NAACP Initial Comments at 21–23; GridLab Initial Comments at 25–28; Interwest Initial Comments at 13–14; ITC Initial Comments at 21–22; Joint Consumer Advocates Initial Comments at 11–12; Large Public Power Initial Comments at 28–29; Michigan Commission Initial Comments at 7; Nevada Commission Initial Comments at 10–11; Northwest and Intermountain Initial Comments at 15–16; NYISO Initial Comments at 39; Pattern Energy Reply Comments at 8–9; PIOs Initial Comments at 43–44; PIOs Reply Comments at 7–8; PJM Initial Comments at 94–96; Policy Integrity Initial Comments at 28; Policy Integrity Supplemental Comments at 4–8; PPL Initial Comments at 14–15; R Street Initial Comments at 9–10; Rail Electrification Initial Comments at 6–7; RMI Initial Comments at 2; SEIA Initial Comments at 16–17; Shell Initial Comments at 14–16; Tabors Caramanis Rudkevich Initial Comments at 6; US DOE Initial Comments at 33–34; Vistra Initial Comments at 15–16; WE ACT Initial Comments at 2–3.

[1823] NOPR, 179 FERC ¶ 61,028 at P 183.

[1824] APPA Initial Comments at 5; Avangrid Initial Comments at 7, 29; Business Council for Sustainable Energy Initial Comments at 5; California Commission Initial Comments at 28–30; California Energy Commission Initial Comments at 3; ENGIE Reply Comments at 3; Handy Law Initial Comments at 8; Massachusetts Attorney General Initial Comments at 3; Michigan Commission Initial Comments at 6; Nebraska Commission Initial Comments at 7; NESCOE Initial Comments at 44 (citing NOPR, 179 FERC ¶ 61,028 at PP 183, 186); NRECA Initial Comments at 46; NYISO Initial Comments at 37–38; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 7; Vermont State Entities Initial Comments at 6.

[1825] Nebraska Commission Initial Comments at 7.

[1826] Certain TDUs Initial Comments at 13; Michigan Commission Initial Comments at 6.

[1827] Certain TDUs Initial Comments at 13–14.

[1828] Certain TDUs Initial Comments at 14–15; Entergy Reply Comments at 4–5 (citing *City & Cnty. of San Francisco* v. *FERC,* 24 F.4th 652, 661 (D.C. Cir. 2022); *Sw. Power Pool, Inc.,* 180 FERC ¶ 61,074, at PP 24–31 (2022), *order on reh'g and setting aside,* 182 FERC ¶ 61,100 (2023)).

[1829] Entergy Reply Comments at 5.

[1830] MISO TOs Initial Comments at 19–22 (citing MISO, Electric Tariff, attach. FF §§ II.C.2, II.C.5; MISO, *LRTP Tranche 1 Portfolio Detailed Business Case,* at 15–49, 60 (June 25, 2022), *https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf*).

[1831] DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13–14; Louisiana Commission Initial Comments at 18; Michigan Commission Initial Comments at 6; US Chamber of Commerce Initial Comments at 7–8. Further detail on the basis for these commenters' concerns is provided *infra.*

[1832] *See, e.g.,* Duke Initial Comments at 24.

[1833] *See, e.g.,* EEI Initial Comments at 20.

clarify that it will not force transmission providers to assign dollar values for every benefit because some benefits' quantification is subjective.[1834] EEI asserts that transmission providers should not have to calculate all of the benefits for a transmission project but states that those benefits used for cost allocation purposes should be quantifiable.[1835] NYISO requests that the final order confirm that it does not prescribe how benefits must be calculated and, more specifically, that transmission providers are not required to calculate the listed benefits in the exact manner described in the NOPR.[1836]

828. MISO notes that the benefits it currently uses in regional transmission planning are not all specified in the Tariff itself but were developed as part of the review process with MISO stakeholders. MISO adds that the flexibility to look for relevant benefits and apply them in long-term planning scenarios is important in the process to identify long-term regional solutions that reflect the needs and value-drivers of the MISO footprint.[1837] MISO states that if limited to a prescriptive set of benefits, MISO may not be in the same position to move forward the transmission projects of the greatest benefit and value to MISO and its stakeholders.[1838]

829. Some commenters opine on requirements or best practices for identifying, measuring, and combining benefits.[1839] For example, some commenters comment on the measurement and/or calculation of benefits.[1840] Entergy argues that the Commission should require all benefits to be reasonably achievable in real-time operations.[1841] SPP Market Monitor states that assumptions into benefit calculations should be improved to ensure that they result in just and reasonable rates.[1842] Large Public Power emphasizes that the Commission should clarify that benefits must reflect load-serving entities' actual use of proposed transmission facilities, measured by anticipated power flows.[1843]

830. SEIA suggests that there are many resources to inform methods for the calculation of benefits, including MISO's Long Range Transmission Plan Tranche 1 portfolio.[1844] Also referencing MISO's process, AEP contends that the benefits of regional transmission facilities should be evaluated collectively, through a multi-value analysis, and cites MISO's existing process as an example.[1845]

831. Some commenters opine on the need for quantification and/or specificity of benefits.[1846] DC and MD Offices of People's Counsel assert that any benefit used should be pre-defined and its measurement accurate and transparent.[1847] PIOs also state that the Brattle-Grid Strategies Oct. 2021 Report provides evidence that benefits from transmission facilities are not difficult to quantify despite claims to the contrary.[1848] NASUCA asserts that the methods for calculating and assigning benefits should be based on objective, measurable, clear, and specific metrics.[1849] Similarly, Illinois Commission, Pacific Northwest Utilities, and NARUC assert that transmission benefits must be verifiable and quantifiable.[1850]

832. A few commenters address the ease of quantification of the benefits listed in the NOPR. NARUC states that NOPR Benefits 1–5 and 8–10 seem somewhat capable of quantification.[1851] NRECA asserts that the benefits at the top of the list in the NOPR are reasonably quantifiable, while those farther down the list require more subjective judgements.[1852] APPA agrees that some of the benefits listed in the NOPR would be more challenging to quantify and therefore would be more difficult to justify as a just and reasonable way to allocate costs.[1853]

833. Some commenters support the use of benefit-cost analysis frameworks.[1854] Michigan State Entities express that having a prescribed benefit-cost analysis framework can help ensure appropriate quantification of benefits, adding that there is less transparency when individual transmission providers may determine how these benefits stack up against each other.[1855] Therefore, Michigan State Entities recommend that the Commission adopt the cost-benefit analysis framework already used throughout the Federal Government. According to Michigan State Entities, the Commission's legal authority to do so is well-established by court decisions and it would help to ensure sufficient regional transmission cooperation to achieve just and reasonable rates.[1856]

834. Six Cities argues that transmission planning should assess both project benefits and costs.[1857] Vermont State Entities agree that a comprehensive benefit-cost analysis would lead to better and more cost-effective transmission planning.[1858] Southern also states that the burdens associated with proposed transmission projects should be recognized, including not only immediate cost and rate impacts, but also effects on local communities and landowners and issues of equity and environmental justice.[1859]

835. Likewise, certain commenters state that they support the adoption of benefit-cost analysis using quantifiable, replicable, non-duplicative, and forward-looking metrics.[1860] US

[1834] Duke Initial Comments at 24.

[1835] EEI Initial Comments at 20.

[1836] NYISO Initial Comments at 36–40.

[1837] MISO Initial Comments at 9–10.

[1838] *Id.* at 9.

[1839] Acadia Center and CLF Initial Comments at 23; ACORE Reply Comments at 3; ACEG Initial Comments at 32; AEP Initial Comments at 21–24; APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 11; Clean Energy Associations Initial Comments at 20–21; DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13–14; Large Public Power Initial Comments at 28; Louisiana Commission Initial Comments at 18; Michigan State Entities Initial Comments at 5–7; NARUC Initial Comments at 20–26; NASUCA Initial Comments at 10; NRECA Initial Comments at 45; NYISO Initial Comments at 37; PJM Market Monitor Initial Comments at 4; SEIA Initial Comments at 18–19; Six Cities Initial Comments at 2–3; Southern Initial Comments at 31; SPP Market Monitor Initial Comments at 11; US Chamber of Commerce Initial Comments at 7–8; US DOE Initial Comments at 31; Vermont State Entities Initial Comments at 6.

[1840] AEP Initial Comments at 21–24; Clean Energy Associations Initial Comments at 21; Large Public Power Initial Comments at 28; SEIA Initial Comments at 18–19; SPP Market Monitor Initial Comments at 11.

[1841] Entergy Initial Comments at 22.

[1842] SPP Market Monitor Initial Comments at 11.

[1843] Large Public Power Initial Comments at 28.

[1844] SEIA Initial Comments at 18–19 (citing Rob Gramlich, *Enabling Low-Cost Clean Energy & Reliable Service Through Better Transmission Benefits Analysis,* at 17, *https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf*).

[1845] AEP Initial Comments at 21–24.

[1846] ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31); Concerned Scientists Reply Comments at 8–10; DC and MD Offices of People's Counsel Initial Comments at 19; Entergy Initial Comments at 22; NASUCA Initial Comments at 10; US DOE Initial Comments at 31.

[1847] DC and MD Offices of People's Counsel Initial Comments at 19.

[1848] PIOs Initial Comments at 42–44.

[1849] NASUCA Initial Comments at 10.

[1850] Illinois Commission Initial Comments at 13–14; NARUC Initial Comments at 20–25; Pacific Northwest Utilities Initial Comments at 8–9.

[1851] NARUC Initial Comments at 21.

[1852] NRECA Initial Comments at 45.

[1853] APPA Initial Comments at 32.

[1854] Michigan State Entities Initial Comments at 5–7; Six Cities Initial Comments at 2–3; Southern Initial Comments at 31; Vermont State Entities Initial Comments at 6–7.

[1855] Michigan State Entities Initial Comments at 5.

[1856] *Id.* at 6–7.

[1857] Six Cities Initial Comments at 2–3.

[1858] Vermont State Entities Initial Comments at 6–7.

[1859] Southern Initial Comments at 31.

[1860] City of New Orleans Council Initial Comments at 11; Entergy Initial Comments at 22; Louisiana Commission Initial Comments at 18; US Chamber of Commerce Initial Comments at 7–8.

Chamber of Commerce contends that the objective nature of such metrics should limit uncertainty otherwise present in projections spanning multiple decades and reduce the variability and error in benefit calculations.[1861] Acadia Center and CLF and ACEG argue that an unbiased analysis of both benefits and costs is essential for ensuring just and reasonable rates and that the Commission should seek to ensure that a minimum set of benefits is applied consistently across RTO/ISO and non-RTO/ISO transmission planning regions.[1862] ACORE agrees with US DOE that consistency in benefit quantification could facilitate improved interregional transmission planning.[1863]

836. Other commenters state that the NOPR's proposed reforms will help improve transmission providers' existing benefit-cost analyses.[1864] GridLab states that the NOPR's approach balances regional flexibility with Federal standardization in benefit categories across transmission providers and more accountability by transmission providers in their benefit-cost analysis.[1865] PJM Market Monitor states that PJM's current benefit-cost analysis does not accurately measure the costs and benefits of transmission projects because it does not account for the fact that benefits are uncertain and sensitive to modeling assumptions or that costs may exceed estimates.[1866] Illinois Commission states that the use of too many metrics could lead to the evaluation of transmission projects based on the margins and inequitable cost allocation.[1867] Illinois Commission further states that some metrics may be most relevant for interregional and regional transmission projects identified in the Long-Term Regional Transmission Planning process and that the Commission can aid transmission planning regions in putting together a shorter list of these metrics.[1868]

c. Commission Determination

837. We adopt the NOPR proposal, with modification, and require transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the seven benefits included in the required set of benefits that we require them to measure and use in Long-Term Regional Transmission Planning. As discussed above, we clarify that transmission providers may use and measure additional benefits, beyond the seven required by this final order.[1869]

838. We find that requiring such a description in transmission providers' OATTs for the seven required benefits is necessary to ensure that all stakeholders have transparency regarding the benefits that transmission providers use to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. We further conclude that requiring inclusion of this information in the OATT will better ensure transmission providers measure and use the set of benefits required in the final order in Long-Term Regional Transmission Planning.

839. Some commenters express concerns regarding excessive quantification of benefits.[1870] But the approach adopted in this final order—of requiring transmission providers to measure and use a required set of benefits in Long-Term Regional Transmission Planning and requiring transmission providers to include in their OATTs a general description of the method they will use to measure each of those benefits—represents a reasonable balance between specificity and flexibility. As discussed above, we provide flexibility to transmission providers to specify the method for measuring each of the seven required benefits. However, because our requirement that transmission providers measure and use these benefits in Long-Term Regional Transmission Planning is necessary to address the identified deficiencies in existing regional transmission planning and cost allocation processes, we find that it is also necessary for transmission providers to include in their OATTs a general description of how they will measure each of these benefits. Such a requirement will ensure that transmission providers consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs.

840. In response to some commenters, such as MISO, that urge that requiring details on measurement of benefits to be incorporated into the OATT could impede development and use of new transmission metrics, we clarify that the description for each required benefit in the OATT must only be sufficient to enable stakeholders to understand the manner by which transmission providers will measure these benefits. We do not require further details on measurement of the benefits to be included in the OATT.

841. Large Public Power asks that the Commission clarify that any acceptable list of benefits detailed in compliance filings must emphasize load-serving entities' actual use of the proposed transmission facilities, which should be measured by anticipated power flows that occur across these facilities.[1871] We decline to adopt Large Public Power's suggested clarification as we are not mandating any particular method for measuring the seven benefits included in the required set of benefits.

842. We decline certain commenters' requests to require that transmission providers justify why they omit any categories of benefits.[1872] Such a requirement is unnecessary because of our modifications to the NOPR proposal, which now require transmission providers to measure and use the required set of benefits in Long-Term Regional Transmission Planning.

4. Evaluation of Transmission Benefits Over a Longer Time Horizon

a. NOPR Proposal

843. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the regional transmission facilities.[1873]

844. The Commission proposed to require transmission providers to evaluate benefits over this time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission

[1861] US Chamber of Commerce Initial Comments at 8.

[1862] Acadia Center and CLF Initial Comments at 23; ACEG Initial Comments at 32.

[1863] ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31).

[1864] GridLab Initial Comments at 25; PJM Market Monitor Initial Comments at 4–5; Southeast PIOs Initial Comments at 49–50.

[1865] GridLab Initial Comments at 25.

[1866] PJM Market Monitor Initial Comments at 4–5.

[1867] Illinois Commission Initial Comments at 13.

[1868] *Id.* at 14.

[1869] While we conclude that it is important for transmission providers to at minimum use and measure the required seven benefits, we agree with MISO that the flexibility to look for relevant benefits and apply them in long-term planning scenarios can be important in the process to identify long-term regional solutions that reflect region-specific needs and value-drivers. MISO Initial Comments at 9. We therefore afford flexibility to transmission planners in identifying and measuring benefits that go beyond the core set of seven required here.

[1870] *See, e.g.,* Duke Initial Comments at 24.

[1871] Large Public Power Initial Comments at 28.

[1872] GridLab Initial Comments at 25; NYISO Initial Comments at 37–38; Vermont State Entities Initial Comments at 6–7.

[1873] NOPR, 179 FERC ¶ 61,028 at P 227.

facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such regional transmission facilities in a manner that is at least roughly commensurate with estimated benefits. The Commission proposed that for consistency and a matching comparison of benefits and costs over time, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, that transmission providers should estimate those future costs over the same time horizon as the estimated benefit.[1874] The Commission proposed that approaches may exceed this minimum requirement, but transmission providers must demonstrate that their proposal is consistent with or superior to any final order in this proceeding.

b. Comments

i. Requirement for a Benefits Evaluation Time Horizon of a Minimum of 20 Years From the In-Service Date

845. Several commenters support the Commission's proposal to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.[1875] NARUC, for example, states that transmission planning must strike a reasonable balance between considering benefits only through the end of the transmission planning horizon regardless of the transmission facility's in-service date and considering benefits over its full expected life, which NARUC states that the NOPR proposal achieves.[1876] Northwest and Intermountain state that they cautiously support the Commission's proposal to establish a minimum 20-year horizon for the calculation of benefits, noting that their concerns are mitigated by the NOPR proposal to allow flexibility within each transmission planning region to tailor cost allocation criteria to that region's needs.[1877] Similarly, Vermont State Entities and NESCOE state that a rigid one-size-fits-all rule could be counterproductive and would not necessarily lead to just and reasonable transmission rates.[1878] NARUC states that, while it supports the NOPR proposal, transmission providers should be allowed independent entity variations to deviate above or below the 20-year horizon after gaining experience with Long-Term Regional Transmission Planning.[1879] NYISO contends that it already employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.[1880]

846. MISO supports the Commission's proposal, stating that a minimum period of 20 years is adequate to assess the benefits of regional transmission facilities.[1881] MISO cautions, however, that the benefits determined over this time horizon represent the minimum benefits that a regional transmission facility provides and that the analysis should recognize that additional benefits would be realized over the life of the investment even if changing system conditions create uncertainty as to the precise value of those benefits.[1882]

847. Other commenters suggest that the time horizon for the evaluation of benefits in Long-Term Regional Transmission Planning should align with the useful life of the transmission asset.[1883] Breakthrough Energy and CARE Coalition contend that the proper time horizon for evaluation of benefits in standard economics and public policy is the life of the transmission asset, noting that transmission assets can often last 40 years or longer.[1884] ACEG agrees, noting that, while it supports use of a 20-year minimum horizon to evaluate benefits, standard regulatory practice for a benefit-cost analysis is typically the life of the asset.[1885] Likewise, PIOs contend that, while they agree with the NOPR proposal, it would be preferable to align the time horizon for evaluating benefits with the useful life of the transmission project.[1886] PIOs state that calculating the benefits and costs of a transmission project over a shorter timespan can understate the benefit-cost ratio because benefits tend to grow over time, while transmission revenue requirements will decline over time as the asset is depreciated.[1887]

848. CTC Global states that while it supports the NOPR proposal, it argues that it would be more appropriate to align the timeline for evaluating benefits with the asset life, because while advanced conductors are almost always more expensive than legacy conductors initially, their costs are offset by efficiency and resilience benefits decades into the future.[1888] Indicated PJM TOs state that benefits "should be calculated on the same time horizon as the project that is being assessed to allow for the ability to properly compare projects." [1889]

849. Given that transmission assets often have a useful life of at least 40 years, US DOE encourages the Commission to require transmission providers to evaluate costs and benefits over a minimum of 30 years after the in-service date of a transmission facility rather than the proposed 20 years. According to US DOE, doing so would better align with the useful life assumptions that generation developers make.[1890]

850. Clean Energy Buyers and PG&E suggest that benefits should be evaluated over the same 20-year horizon as the proposed Long-Term Regional Transmission Planning transmission planning horizon.[1891] Similarly, PPL states that, while it supports the proposed 20-year minimum duration to evaluate benefits in Long-Term Regional Transmission Planning, the Commission should require transmission providers to measure benefits from the study date rather than the proposed in-service date of the Long-Term Regional Transmission Facility. PPL contends that the NOPR proposal would introduce significant variability that will make it challenging to align the outcome with the long-term need and would incentivize transmission developers to delay or adjust the timing

[1874] *Id.* P 228.

[1875] ACEG Initial Comments at 24; California Commission Initial Comments at 36; Certain TDUs Reply Comments at 3; ITC Initial Comments at 22–23; NARUC Initial Comments at 26–27; NYISO Initial Comments at 40; OMS Initial Comments at 8–9; Pacific Northwest State Agencies Initial Comments at 16–19.

[1876] NARUC Initial Comments at 26.

[1877] Northwest and Intermountain Initial Comments at 8.

[1878] NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 6.

[1879] NARUC Initial Comments at 39–40.

[1880] NYISO Initial Comments at 40.

[1881] MISO Initial Comments at 52.

[1882] *Id.*

[1883] ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16–17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 17–18; Interwest Initial Comments at 14; Interwest Reply Comments at 6–7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40–41; US DOE Initial Comments at 33–34; WIRES Initial Comments at 7.

[1884] Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41.

[1885] ACEG Initial Comments at 24.

[1886] PIOs Initial Comments at 40 (citing PIOs Initial Comments Ex. A, ¶¶ 24–29).

[1887] *Id.* (citing PIOs Initial Comments Ex. A, ¶ 28).

[1888] CTC Global Initial Comments at 16–17.

[1889] Indicated PJM TOs Initial Comments at 18.

[1890] US DOE Initial Comments at 33–34.

[1891] Clean Energy Buyers Initial Comments at 20; PG&E Initial Comments at 7.

of transmission projects to maximize the demonstrated benefit.[1892]

851. In contrast, GridLab contends that the 20-year Long-Term Regional Transmission Planning transmission planning horizon need not correspond with the time horizon over which transmission providers evaluate the benefits and costs of potential transmission investments. GridLab recommends that the Commission clarify the distinction between the requirement for a 20-year transmission planning horizon and for a 20-year period to evaluate benefits, while keeping both requirements.[1893]

852. Many commenters assert that evaluating benefits over a 20-year time horizon is difficult or speculative.[1894] Ohio Consumers and Dominion argue that, since transmission providers would be required to plan for potential transmission needs in 20 years and evaluate benefits over a 20-year project life span, the requirement effectively amounts to a 40-year cost allocation process and will be particularly challenging.[1895] APS agrees, stating that calculating benefits over a potential 40 years may lead to benefit calculations that are overstated or yield unreasonable or unrealistic results.[1896]

853. Some commenters request certain clarifications or modifications to address that uncertainty.[1897] For example, Exelon states that benefits should tie back to customer value and suggests that the Commission should give transmission providers flexibility to assign more weight to nearer-term benefits tied to specific savings that are more certain.[1898] SERTP Sponsors and Duke agree, and Duke requests that the Commission clarify that transmission providers are permitted to discount benefits based on increased uncertainty in later years for purposes of evaluating, selecting, and allocating the costs of Long-Term Regional Transmission Facilities.[1899]

854. Several commenters oppose requiring a minimum 20-year horizon for evaluating benefits of Long-Term Regional Transmission Facilities.[1900] For example, Idaho Commission argues that the NOPR proposal is founded on benefits that are not ''generally accepted or regionally flexible'' and may not be beneficial for regional transmission planning benefit evaluation.[1901] Furthermore, Idaho Commission argues, it is difficult to accurately predict and quantify benefits over a 20-year period for purposes of cost allocation.[1902]

855. Similarly, Dominion requests that the Commission decline to adopt the NOPR proposal or provide clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period. Dominion states that it would be unreasonable for the Commission to require transmission providers to consider benefits over a 40-year period, because identifying benefits and beneficiaries that far into the future would involve too much speculation.

856. Pennsylvania Commission requests that the Commission revise the NOPR proposal to set a long-term horizon of no longer than 20 years for planning and benefit-cost analysis. Pennsylvania Commission argues that as the planning and benefit-cost analysis horizons lengthen, uncertainty in predictions of load growth, costs, and benefits will increase, potentially leading to uneconomic transmission projects.[1903] Pacific Northwest Utilities oppose the NOPR proposal because, they argue, beneficiaries and benefits cannot be identified or quantified with any reasonable certainty over a 20-year transmission planning horizon. Specifically, Pacific Northwest Utilities contend that there is no plausible reason to believe that such speculative benefits would be roughly commensurate with the costs that are allocated to identified beneficiaries.[1904]

ii. Applicability of Benefits Evaluation Horizon to Long-Term Regional Transmission Planning Stages (Evaluation of Facilities, Selection, and Cost Allocation)

857. Pacific Northwest State Agencies supports the Commission's proposal to require that transmission providers evaluate benefits over a consistent time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such transmission facilities in a manner that is roughly commensurate with estimated benefits.[1905]

858. Several commenters also support the Commission's proposal that, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, they should estimate those future costs over the same time horizon as the estimated benefits.[1906] For instance, MISO states that costs and benefits for regional transmission investments should be evaluated using the same time horizon to ensure there is consistency in accounting for the effects of time in the calculations.[1907] MISO attests that since benefits are only realized once a transmission project or portfolio of projects is in service, transmission providers should assess the benefits over the period of time starting with the in-service date to align with costs.[1908] Pacific Northwest State Agencies and Certain TDUs agree.[1909]

c. Commission Determination

859. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, and we require that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities.[1910] However,

[1892] PPL Initial Comments at 15–17.

[1893] GridLab Initial Comments at 6–8.

[1894] APPA Initial Comments at 32; Dominion Initial Comments at 17; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; PJM Initial Comments at 97.

[1895] Ohio Consumers Initial Comments at 8.

[1896] APS Initial Comments at 8–9.

[1897] Duke Initial Comments at 23–24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

[1898] Exelon Initial Comments at 16.

[1899] Duke Initial Comments at 23–24; SERTP Sponsors Initial Comments at 31.

[1900] Dominion Reply Comments at 4–5; Idaho Commission Initial Comments at 4; NARUC Initial Comments at 5–6; NESCOE Initial Comments at 44–45; Pacific Northwest Utilities Initial Comments at 6–7; Pennsylvania Commission Initial Comments at 4–5.

[1901] Idaho Commission Initial Comments at 4.

[1902] *Id.*

[1903] Pennsylvania Commission Initial Comments at 4–5.

[1904] Pacific Northwest Utilities Initial Comments at 7 (citing *ICC* v. *FERC I,* 576 F.3d 470).

[1905] Pacific Northwest State Agencies Initial Comments at 18.

[1906] Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); MISO Initial Comments at 53; NARUC Initial Comments at 27; OMS Initial Comments at 8–9; Pacific Northwest State Agencies Initial Comments at 18.

[1907] MISO Initial Comments at 53.

[1908] *Id.*

[1909] Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); Pacific Northwest State Agencies Initial Comments at 18.

[1910] In the NOPR, the Commission used the term ''regional transmission facilities''; however, as this reform only concerns Long-Term Regional Transmission Planning, we clarify that the Commission's intent was to refer only to Long-Term Regional Transmission Facilities. As discussed in the Development of Long-Term Scenarios section, transmission providers also use these benefits to help to inform their identification of Long-Term we do not adopt the NOPR proposal to require a minimum 20-year horizon to calculate benefits for purposes of cost allocation. As described in the Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities section of this final order, requiring transmission providers to adopt this provision for purposes of cost allocation would unduly complicate development and review of Long-Term Regional Transmission Cost Allocation Methods, with little incremental gain. Lastly, for consistency and a matching comparison of costs over time, we adopt the NOPR proposal to require that, to the extent that transmission providers estimate the costs of Long-Term Regional Transmission Facilities beyond the in-service date of the transmission facilities, they must estimate those future costs over the same time horizon as the estimated benefits.

860. We find that calculating benefits both for the evaluation and selection of Long-Term Regional Transmission Facilities over a timeline that covers, at a minimum, 20 years starting from the estimated in-service date of the Long-Term Regional Transmission Facility, strikes an appropriate balance. This balance reasonably reflects the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, a time period that can exceed 40 years,[1911] while recognizing the inherent difficulties in attempting to predict system conditions too far into the future. As described in the Long-Term Regional Transmission Planning section of this final order, the uncertainty associated with forecasting future transmission needs over a long-term transmission planning horizon can be mitigated through the use of multiple Long-Term Scenarios and sensitivities.

861. Specifically, this final order requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and also requires transmission providers to update their assumptions periodically. Additionally, transmission providers are permitted to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in Factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios.[1912] Because of these reforms, we believe that transmission providers will be able to identify Long-Term Transmission Needs with a higher likelihood of occurrence, and, therefore, the benefits resulting from Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address these Long-Term Transmission Needs will similarly be more certain.

862. Moreover, as described in the Evaluation and Selection of Regional Transmission Facilities section of this final order, we provide transmission providers with considerable flexibility to develop an evaluation process and selection criteria that will provide them the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities. In particular, transmission providers have the flexibility to evaluate Long-Term Regional Transmission Facilities and their measured benefits across the different Long-Term Scenarios and sensitivities in a manner that addresses the inherent uncertainty in Long-Term Regional Transmission Planning, for example through the use of a least-regrets or a weighted-benefits approach. Lastly, as is the case under the existing Order No. 1000 regional transmission planning processes, the final order does not require transmission providers to select any transmission facilities as part of Long-Term Regional Transmission Planning. Taken together, the aspects of the final order described above offer transmission providers meaningful tools to address uncertainty in Long-Term Regional Transmission Planning, including the calculation of benefits.

863. We disagree with NESCOE and Vermont State Entities, who argue that a requirement to calculate benefits over a minimum of 20 years from the estimated in-service date is overly rigid and may not lead to transmission rates that are just and reasonable. As discussed above, this requirement strikes a reasonable balance between the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, while recognizing the inherent difficulties in attempting to forecast system conditions too far into the future. Further, allowing transmission providers to calculate benefits over a shorter period would more likely undervalue the total benefits that Long-Term Regional Transmission Facilities can provide and could therefore lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected to address Long-Term Transmission Needs. Lastly, and as stated above, we are not requiring transmission providers to use a minimum 20-year horizon to calculate benefits for purposes of cost allocation.

864. Similarly, we also disagree with commenters that suggest that the results of the benefits evaluation would not be accurate or dependable enough for transmission providers to use in making the decision to select Long-Term Regional Transmission Facilities.[1913] We further note that transmission providers in multiple transmission planning regions already evaluate the benefits of transmission facilities over a 20-year time horizon as part of their regional transmission planning processes.[1914] For example, NYISO states that it employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.[1915]

865. Some commenters suggest that the Commission should provide additional flexibility to account for uncertainty in calculating benefits over a minimum 20-year time horizon, including that the Commission make clear that transmission providers may discount or weight the calculated benefits based on the relative certainty throughout the benefits horizon.[1916] As

Transmission Needs that manifest during the 20-year transmission planning horizon.

[1911] ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16–17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 18; Interwest Initial Comments at 14; Interwest Reply Comments at 7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40–41; US DOE Initial Comments at 33–34; WIRES Initial Comments at 7.

[1912] *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Categories of Factors section.

[1913] APPA Initial Comments at 32; APS Initial Comments at 8–9; Dominion Initial Comments at 17; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 7; PJM Initial Comments at 97.

[1914] MISO Initial Comments at 52; NYISO Initial Comments at 40; *see also* MISO, *LRTP Business Case,* Long Range Transmission Planning Workshop, at 7 (Jan. 21, 2022, revised Feb. 2, 2022), *https://cdn.misoenergy.org/20220121%20LRTP%20Workshop%20Item%2004%20Business%20Case%20Presentation619895.pdf;* CAISO, *20-Year Transmission Outlook* (Jan. 31, 2022), *http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf;* SPP Engineering, *2021 SPP Transmission Expansion Plan Report* (Jan. 11, 2021), *https://spp.org/documents/56611/2021%20step%20report.pdf.*

[1915] NYISO Initial Comments at 40.

[1916] Duke Initial Comments at 23–24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

we described above, this final order affords transmission providers considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning, including by allowing transmission providers to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. Given these flexibilities, we find that while transmission providers may discount the benefits calculated for purposes of determining a present value of those benefits, they may not further discount those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits.

866. In response to Dominion's request for clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period, we reiterate that transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities over a minimum of 20 years from their estimated in-service date, even if the estimated in-service date is 20 years into the future. The failure to take such an approach could result in transmission providers' consideration of a Long-Term Regional Transmission Facility's cost but not the facility's corresponding benefits.

867. We also decline to modify the proposal, as requested by Pennsylvania Commission,[1917] to require a benefits horizon of no longer than 20 years as a means of reducing speculation and uncertainty in calculating benefits of Long-Term Regional Transmission Facilities, as well as NARUC's request that the Commission permit transmission providers to deviate below the 20-year benefit evaluation horizon. As explained above, a minimum of 20 years strikes a reasonable balance for calculating the benefits of Long-Term Regional Transmission Facilities. In addition, as indicated by many commenters, calculating the benefits of a Long-Term Transmission Facility over a time horizon longer than 20 years is consistent with the long life of transmission facilities—which generally exceeds 20 years by a substantial margin—and also consistent with the fact that transmission facilities may provide significant benefits over their entire useful life. While we reiterate that transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, to the extent that transmission providers would like to consider a longer time horizon for the evaluation of benefits, they may propose to do so on compliance.

868. In response to Pacific Northwest Utilities' argument that transmission providers will be unable to identify the beneficiaries of Long-Term Regional Transmission Facilities over a 20-year time horizon, and therefore that the costs of Long-Term Regional Transmission Facilities will not be allocated in a manner that is roughly commensurate with the benefits received,[1918] we note that this final order modifies the NOPR proposal and transmission providers are not required to use a benefits time horizon of 20 years for purposes of cost allocation. We find this modification to the final order moots Pacific Northwest Utilities' argument.

869. We disagree with PPL's comments arguing that calculating benefits from the estimated in-service date of a Long-Term Regional Transmission Facility will present challenges to align the outcome with the actual needs in Long-Term Regional Transmission Planning or otherwise create perverse incentives for transmission developers to delay or adjust the timing of certain transmission projects to maximize benefits.[1919] To the contrary, establishing a minimum benefits horizon of 20 years starting from the estimated in-service date of Long-Term Regional Transmission Facilities will allow for a comparable evaluation of benefits that identified Long-Term Regional Transmission Facilities may provide, even when such facilities may be placed in service at different times during the transmission planning horizon. We therefore decline PPL's request that the Commission modify the proposal to require that transmission providers measure benefits for a minimum of 20 years starting from the study date, rather than the estimated in-service date of the Long-Term Regional Transmission Facility.

870. In response to GridLab's request that the Commission clarify the distinction between the requirements for a minimum 20-year transmission planning horizon and a minimum 20-year benefits evaluation period,[1920] we reiterate the example provided in the NOPR whereby, if the Long-Term Regional Transmission Planning process identifies a Long-Term Regional Transmission Facility that is estimated to be in service in year 10 of the 20-year Long-Term Regional Transmission Planning horizon, then the estimate of benefits for that same facility will commence at year 10 and cover an additional 20 years. Thus, the requirement to use a 20-year transmission planning horizon is separate and distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from its estimated in-service date.

5. Evaluation of the Benefits of Portfolios of Transmission Facilities

a. NOPR Proposal

871. In the NOPR, the Commission proposed to provide transmission providers in each transmission planning region with the flexibility to propose to use a portfolio approach in the evaluation of benefits of regional transmission facilities through their Long-Term Regional Transmission Planning. Rather than mandating its use, the Commission encouraged the use of this approach by transmission providers.[1921] The Commission proposed to require transmission providers that propose to use a portfolio approach to include in their OATTs provisions describing how they would analyze the benefits of regional transmission facilities under such an approach and whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally or would be used only in certain specified instances.[1922]

b. Comments

i. General Interest in the Use of Portfolios

872. Most commenters who addressed the issue support the use of a portfolio approach to the evaluation of the benefits of regional transmission facilities in Long-Term Regional Transmission Planning, under which transmission providers would evaluate multiple transmission facilities in an aggregated, integrated fashion rather than doing so on a facility-by-facility basis.[1923] Exelon states that benefits

[1917] Pennsylvania Commission Initial Comments at 4–5.

[1918] Pacific Northwest Utilities Initial Comments at 7 (citing *ICC* v. *FERC I,* 576 F.3d 470).

[1919] PPL Initial Comments at 15–17.

[1920] GridLab Initial Comments at 6–8.

[1921] NOPR, 179 FERC ¶ 61,028 at PP 233–234.

[1922] *Id.* P 234.

[1923] *See, e.g.,* Acadia Center and CLF Initial Comments at 10; ACEG Initial Comments at 49; ACORE Initial Comments at 2; AEP Initial Comments at 6, 27–28; Ameren Initial Comments at 19; Clean Energy Associations Initial Comments at 10; Eversource Initial Comments at 25; Exelon assessments for portfolios are likely to be more robust and less sensitive to changes in study assumptions than project-by-project analyses, tend to have widely distributed benefits, which can help garner stakeholder support, and may provide for administrative efficiencies in transmission planning.[1924] ACEG states that portfolio planning more accurately evaluates the benefits that new transmission provides to the system.[1925] Georgia Commission states that evaluating transmission facilities collectively, rather than on a facility-by-facility basis, may provide a better picture of the benefits to each state or transmission planning region and result in a more robust selection of transmission facilities.[1926]

873. Renewable Northwest states that using portfolios in transmission planning is a best practice because it more completely captures systems benefits and leads to cost efficiencies.[1927] Renewable Northwest also comments that singularly focused planning processes often fail to identify the most cost-effective and efficient investments and instead have led to a bottom-up approach that has created a patchwork of transmission projects with high costs largely borne by ratepayers.[1928] EEI explains that the portfolio approach comprehensively addresses a number of transmission needs while ensuring a ''no regrets'' set of beneficial regional transmission projects.[1929] Eversource states that a portfolio approach can allow transmission providers to devise a set of transmission solutions that collectively create the most value compared to a piecemeal process.[1930]

874. AEP states that the portfolio approach offers three advantages: (1) it enables transmission planning regions to identify transmission projects with synergistic benefits across transmission planning regions because regions will be able to recognize the efficiencies of a collection of transmission projects that provide greater overall value to the grid together than they each provide on an individual basis; (2) there are administrative efficiencies; and (3) a portfolio approach best incorporates consideration of non-transmission alternatives and grid-enhancing technologies.[1931]

875. Numerous commenters point to the MISO Multi-Value Project process as an example of the successful use of portfolios.[1932] Clean Energy Associations state that the Multi-Value Project process has resulted in lower interconnection costs for generators as compared to transmission upgrades planned in response to interconnection requests.[1933] US DOE suggests the Multi-Value Project process is an example of the use of portfolios to generate benefits that exceed costs.[1934] MISO states that it has worked with stakeholders to apply broad benefit metrics in the evaluation of Multi-Value Projects to identify portfolios of projects with benefits spread broadly throughout the region.[1935]

876. Some commenters believe that the Commission should require the use of portfolios in the evaluation of benefits of regional transmission facilities.[1936] US DOE supports requiring transmission planners to evaluate the benefits of proposed transmission facilities as a portfolio, rather than as individual investments, to reduce the uncertainty of estimating system-level benefits, to simplify cost allocation, and to reduce administrative burden.[1937] US DOE states that if the portfolio approach is inappropriate in a particular circumstance, the impacted entities could petition the Commission, on a case-by-case basis, to describe their proposed alternative approach.[1938]

877. New Jersey Commission states that the evidence from multiple studies of and experiences with long-term multi-driver and portfolio-based transmission planning proves that these approaches save ratepayers billions of dollars and failure to use them is *per se* unjust and unreasonable.[1939] Cypress Creek argues that a portfolio approach is essential to optimize benefits and reduce the likelihood of a state or agency derailing a transmission project with proven regional benefits.[1940]

878. PIOs state that the costs of a transmission project in a rural area that enhances access to renewable resources may exceed its benefits when evaluated alone, but, if evaluated with another project that relieves congestion, the two projects may support power flows that would not otherwise be possible.[1941] PIOs further state that portfolio planning can reduce the risk that transmission projects are underutilized because they were built for a single resource that is no longer used or only a narrow set of users were considered.[1942]

879. ITC argues that the Commission should mandate the use of a portfolio approach in RTO/ISOs to ensure that the most efficient, cost-effective, and broadly beneficial set of transmission projects are selected in each transmission planning cycle.[1943] ITC states that the use of a portfolio approach ensures that the greatest number of subregions within a transmission planning region receive benefits from each transmission planning cycle and provides significant efficiency gains because transmission providers can examine the whole portfolio to ensure that benefits exceed costs.[1944]

880. Pattern Energy urges the Commission to require transmission providers to adopt portfolio approaches and explain why a portfolio approach was not (or could not be) identified in any Long-Term Regional Transmission Plan when an incremental transmission solution is proposed.[1945] Pattern Energy suggests that, if the Commission does not require portfolios, it should set a voltage threshold to identify portfolio solutions and require that transmission providers must explain why a portfolio approach was not taken when proposing incremental transmission facilities at voltage levels above 100 kV.[1946] Similarly, Shell states that if the Commission does not require a portfolio approach, it should require transmission

Initial Comments at 15–16; Joint Consumer Advocates Initial Comments at 11; Massachusetts Attorney General Initial Comments at 15–16; Pacific Northwest State Agencies Initial Comments at 7; PG&E Initial Comments at 8; PJM Reply Comments at 23; PIOs Initial Comments at 28; TANC Initial Comments at 16; US DOE Initial Comments at 34–35.

[1924] Exelon Initial Comments at 15–16, 18 (citing NOPR, 179 FERC ¶ 61,028 at P 233).

[1925] ACEG Initial Comments at 49.

[1926] Georgia Commission Initial Comments at 7.

[1927] Renewable Northwest Initial Comments at 9–10 (citing Brattle-Grid Strategies Oct. 2021 Report at 23).

[1928] *Id.* at 9.

[1929] EEI Initial Comments at 15.

[1930] Eversource Initial Comments at 25.

[1931] AEP Initial Comments at 27–28.

[1932] *See, e.g.,* EEI Initial Comments at 15; Clean Energy Associations Initial Comments at 10; MISO Initial Comments at 14; US DOE Initial Comments at 34–35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65–66).

[1933] Clean Energy Associations Initial Comments at 10.

[1934] US DOE Initial Comments at 35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65–66).

[1935] MISO Initial Comments at 14.

[1936] Acadia Center and CLF Initial Comments at 4–5; ACEG Initial Comments at 31, 48–49; Cypress Creek Reply Comments at 8–9; ITC Initial Comments at 6, 23–24; Pattern Energy Initial Comments at 15–17; Pine Gate Initial Comments at 38–39; PIOs Initial Comments at 28; SEIA Initial Comments at 20–21; US DOE Initial Comments at 34–35; WATT Initial Comments at 8–9.

[1937] US DOE Initial Comments at 34–35.

[1938] *Id.* at 35.

[1939] New Jersey Commission Initial Comments at 7.

[1940] Cypress Creek Reply Comments at 9.

[1941] PIOs Initial Comments at 31–32.

[1942] *Id.* at 36.

[1943] ITC Initial Comments at 6, 23–24.

[1944] *Id.* at 23.

[1945] Pattern Energy Initial Comments at 15–17.

[1946] *Id.* at 17.

providers to explain why portfolios are not being used.[1947]

ii. Interest in Flexibility in the Use of Portfolios

881. Many other commenters assert that the Commission should only permit, not require, the use of portfolios in the evaluation of benefits.[1948] For example, Duke states that a facility-by-facility approach may be better suited if Long-Term Scenarios reveal the same or nearly identical constraints in discrete and isolated areas of the transmission grid where upgrades would be beneficial, whereas if Long-Term Scenarios reveal more disparate issues in different scenarios a portfolio approach may be better suited to gaining consensus and allowing for more even distribution of benefits.[1949] Duke asks the Commission to provide that, on compliance, a transmission provider may document processes for switching between or using both a facility-by-facility analysis and a portfolio approach.[1950]

882. Dominion Energy states that some transmission providers may not have a portfolio of transmission projects to examine. NYISO asserts that transmission providers should not be required to mix and match components of different transmission developers' proposed transmission solutions to develop a portfolio to address a single transmission need.[1951] APPA and TANC urge the Commission to allow regional flexibility to use a portfolio approach to evaluate benefits.[1952]

883. PPL argues that a portfolio approach should not be mandated because one-size-fits-all portfolio-based planning may have downsides and may not be applicable in all circumstances or transmission planning regions.[1953] PPL further states that relying on portfolios could lead to complications in siting and cost allocation.[1954] Relatedly, Michigan Commission argues that requiring portfolios could cause unnecessary delays for transmission projects that have strong stakeholder buy-in and incentivize including transmission projects less deserving of regional cost allocation purely to bolster assertions that all zones in multi-state RTOs/ISOs will benefit.[1955]

884. CAISO states that portfolio planning should be optional, arguing that CAISO's sequential transmission planning approach achieves multi-benefit and holistic objectives without requiring a portfolio approach.[1956] CAISO explains that a project-by-project review does not mean examining only one transmission need at a time or failing to consider transmission projects that meet multiple needs or deliver multiple benefits.[1957]

iii. Interest in Including the Portfolio Approach in a Transmission Provider's OATT

885. In response to the Commission's proposal that a transmission provider that proposes a portfolio approach must include in its OATT a description of when it would use the approach and how it would analyze benefits, some commenters agree that even if use of portfolios is flexible, the Commission should have such a requirement.[1958] Vermont State Entities suggest that if a transmission provider elects to use a portfolio approach, it must include in its OATT a description of how it would use such an approach and whether that approach would be used universally or only in certain specified instances.[1959]

iv. Integrating Economic and Reliability Planning With Long-Term Regional Transmission Planning

886. PIOs state that portfolio planning is necessary and that the use of portfolios should incorporate long-term reliability and economic needs and benefits along with long-term Public Policy Requirements, because doing so allows transmission providers to select transmission projects with the higher benefit-to-cost ratios that resolve needs at least cost.[1960] PIOs state that by assessing all transmission needs at once and evaluating potential solutions, stakeholders will be able to find more efficient solutions that address multiple transmission needs that affect different jurisdictions simultaneously.[1961] PIOs ask that the final order allow transmission providers to continue to address unforeseen short-term local reliability needs but establish a rebuttable requirement that all long-term economic, public policy, and regional reliability needs and benefits will be assessed on a portfolio basis in Long-Term Regional Transmission Planning.[1962]

887. SEPA states that the portfolio approach can be further enhanced by considering all categories of benefits: reliability, economic, public policy, and resilience.[1963] Likewise, SEIA states that the Commission should require portfolio-based planning that integrates all relevant factors, reliability, economic, and public policy, into Long-Term Regional Transmission Planning.[1964] Acadia Center and CLF discuss portfolio planning as integrating Long-Term Regional Transmission Planning with economic and reliability planning and state that the final order should require portfolio-based planning that assesses economic, reliability, and other needs at the same time.[1965]

v. Concerns With the Portfolio Approach

888. A few commenters express apprehension about the portfolio approach, including concerns that the use of portfolios may mask bad individual transmission projects in a portfolio or result in good transmission projects not being approved because of difficulties in obtaining multiple state approvals that may be necessary for a portfolio.[1966] For example, Pennsylvania Commission states that a portfolio approach may cause siting concerns if a single transmission project in a portfolio is found by a state siting authority to be inconsistent with its state's public interest and siting regulations.[1967] Idaho Commission opposes requiring the use of a portfolio under any circumstances, stating that flexibility is necessary in transmission planning. It further states that a Commission requirement to use a portfolio approach under certain circumstances without specifying what

[1947] Shell Initial Comments at 16.

[1948] APPA Initial Comments at 32; Arizona Commission Initial Comments at 8; California Commission Initial Comments at 36–37; Dominion Initial Comments at 36; Duke Initial Comments at 25; Georgia Commission Initial Comments at 25; Michigan Commission Initial Comments at 8; MISO Initial Comments at 54; NARUC Initial Comments at 27–29; Nebraska Commission Initial Comments at 7–8; NESCOE Initial Comments at 45; NYISO Initial Comments at 9, 41–42; PPL Initial Comments at 16–17; SDG&E Initial Comments at 3; SPP Initial Comments at 10; TANC Initial Comments at 16; TAPS Initial Comments at 14; Vermont State Entities Initial Comments at 7; Xcel Initial Comments at 12.

[1949] Duke Initial Comments at 25–26.

[1950] *Id.* at 25.

[1951] NYISO Initial Comments at 41.

[1952] APPA Initial Comments at 32; TANC Initial Comments at 16.

[1953] PPL Initial Comments at 16–17.

[1954] *Id.* at 17.

[1955] Michigan Commission Initial Comments at 8.

[1956] CAISO Reply Comments at 22.

[1957] *Id.* at 21–22.

[1958] Clean Energy Associates Initial Comments at 14; NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 7.

[1959] Vermont State Entities Initial Comments at 7.

[1960] PIOs Initial Comments at 30–32.

[1961] *Id.* at 35.

[1962] PIOs Initial Comments at 32.

[1963] SEPA Initial Comments at 1.

[1964] SEIA Initial Comments at 20–21.

[1965] Acadia Center and CLF Initial Comments at 4–5.

[1966] CAISO Reply Comments at 24; Duke Initial Comments at 25–26; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 26; NARUC Initial Comments at 28; Pennsylvania Commission Initial Comments at 10; PPL Initial Comments at 17.

[1967] Pennsylvania Commission Initial Comments at 10.

these circumstances are could result in unjust and unreasonable rates.[1968] Louisiana Commission also opposes any requirement to use a portfolio approach and disagrees with the NOPR's encouragement of such an approach.[1969]

c. Commission Determination

889. We adopt the NOPR proposal to allow, but not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities. Further, we adopt with modification the NOPR proposal to require transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities to include provisions in their OATTs regarding their use of the portfolio approach. While we adopt the NOPR proposal to require transmission providers to include provisions in their OATTs regarding their use of a portfolio approach, we do not adopt the other proposed requirements. Specifically, we decline to adopt the NOPR proposal to require transmission providers to indicate whether a portfolio approach will be used universally or only in certain specified instances or to describe how they will analyze the benefits of regional transmission facilities under a portfolio approach. These requirements could impede transmission provider consideration and development of portfolio approaches. In response to Duke's request that the final order provide transmission providers with the flexibility to switch between or use both facility-by-facility and portfolio approaches,[1970] we clarify that transmission providers may use either or both facility-by-facility and portfolio approaches within the same Long-Term Regional Transmission Planning cycle.

890. We find that there are numerous advantages to a portfolio approach to evaluating benefits, including administrative efficiencies related to economies of scale and a more stable or even distribution of benefits that may result from a portfolio evaluation, which is likely to facilitate agreement on regional cost allocation. However, these advantages must be balanced against other considerations, and we therefore find that providing transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach is appropriate. Accordingly, we decline the request of some commenters[1971] to require transmission providers to use a portfolio approach.

6. Issues Related to Use of Benefits

a. NOPR Proposal

891. The Commission in the NOPR declined, consistent with Order No. 1000, to propose to prescribe any particular definition of ''benefits'' or ''beneficiaries.''[1972]

b. Comments

892. Some commenters request specific definitions for the terms ''benefits'' or ''beneficiaries'' or offer guidance on definitions.[1973] NASUCA urges the Commission not to define benefits so broadly that every transmission project would qualify to be built, stating that overly broad benefit definitions reduce any rational relationship between cost allocation and identifiable beneficiaries.[1974]

893. In contrast, other commenters agree with the Commission's proposal not to define ''benefits'' or ''beneficiaries.''[1975] For example, OMS and the Indiana Commission express support for the NOPR proposal to allow for flexibility in determining the definitions of benefits and beneficiaries for the purpose of selecting transmission facilities in Long-Term Regional Transmission Planning.[1976]

894. Some commenters call for a state role in identifying benefits or metrics for use in Long-Term Regional Transmission Planning.[1977] California Commission states that the Commission should require transmission providers to demonstrate that they consulted with the Relevant State Entities in their transmission planning region regarding benefits metrics.[1978] California Commission further states that the Commission should require transmission providers to indicate in their compliance filings whether their proposed benefits and metrics are supported by the Relevant State Entities, as well as to explain any points of disagreement.[1979] Likewise, New York Commission and NYSERDA state that, especially in single-state RTOs/ISOs, the state should be afforded a central role in determining the benefits that transmission providers will consider and the metrics for quantifying them.[1980]

895. North Carolina Commission and Staff state that, given the focus of the NOPR on transmission needs driven by changes in the generation mix and demand, which are areas of state jurisdiction, the Commission should require state agreement at every stage of the Long-Term Regional Transmission Planning process from identification of transmission needs, to the evaluation of the benefits of regional transmission facilities to meet those needs, to establishment of selection criteria, and finally to establishment of a cost allocation method.[1981] Similarly, NESCOE explains that, while transmission providers have the technical expertise to identify, calculate, and explain the benefits that a given transmission facility may provide, states must be involved where state laws and policies are the project drivers.[1982] As such, NESCOE requests that the Commission require that transmission providers either elevate and codify the states' role in all four phases of Long-Term Regional Transmission Planning or explain how and why, following consultation with the Relevant State Entities, the transmission provider developed a different approach.[1983] NESCOE asserts that this requirement would ensure that states, if they so elect, have a defined role in the evaluation phase of Long-Term Regional Transmission Planning.[1984]

896. Virginia Commission Staff contends that the NOPR-identified benefits should be used only if affected

[1968] Idaho Commission Initial Comments at 4.

[1969] Louisiana Commission Initial Comments at 26.

[1970] Duke Initial Comments at 25–26.

[1971] Acadia Center and CLF Initial Comments at 4–5; ACEG Initial Comments at 31, 48–49; Cypress Creek Reply Comments at 8–9; ITC Initial Comments at 6, 23–24; Pattern Energy Initial Comments at 16–18; Pine Gate Initial Comments at 38–39; PIOs Initial Comments at 28; SEIA Initial Comments at 20–21; US DOE Initial Comments at 34–35; WATT Initial Comments at 8–9.

[1972] NOPR, 179 FERC ¶ 61,028 at P 183 & n.324 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 624–625).

[1973] ELCON Initial Comments at 14–15; NASUCA Initial Comments at 10.

[1974] NASUCA Initial Comments at 10.

[1975] APPA Initial Comments at 31–33; Clean Energy Buyers Reply Comments at 9; Georgia Commission Initial Comments at 6–7; Indiana Commission Initial Comments at 6–7; Louisiana Commission Reply Comments at 9–10; Nebraska Commission Initial Comments at 7; TANC Initial Comments at 16; US Chamber of Commerce Initial Comments at 7–8.

[1976] Indiana Commission Initial Comments at 6–7; OMS Initial Comments at 13.

[1977] California Commission Initial Comments at 35; Massachusetts Attorney General Initial Comments at 14; Michigan Commission Initial Comments at 7–8; NESCOE Initial Comments at 41–43; North Carolina Commission and Staff Initial Comments at 6; PJM Market Monitor Initial Comments at 4.

[1978] California Commission Initial Comments at 35.

[1979] *Id.*

[1980] New York Commission and NYSERDA Initial Comments at 8.

[1981] North Carolina Commission and Staff Initial Comments at 6.

[1982] NESCOE Initial Comments at 41–43.

[1983] *Id.* at 9–10, 41–43.

[1984] *Id.* at 41–43.

states agree to their use.[1985] PJM Market Monitor agrees that it makes sense to attempt an evaluation of a broad set of benefits and beneficiaries through increased state involvement.[1986]

897. Michigan Commission asserts that state regulators should be afforded substantial deference in identifying what benefit metrics and calculation methods should be used to justify long-term transmission plans, arguing that states with objections or concerns that an approved benefit metric is too speculative or otherwise inappropriate may find it more challenging to justify ratepayer investments and land condemnation in state siting proceedings.[1987] Massachusetts Attorney General states that the Commission should require that transmission providers establish an open and transparent process that provides states and other stakeholders with a meaningful opportunity to participate in the process of identifying the benefits to be used in Long-Term Regional Transmission Planning and determining how such benefits will be calculated.[1988] Several commenters state that decisions regarding benefit determination, metrics, and implementation of metrics should be made in coordination with all stakeholders.[1989] NRECA and Vermont State Entities assert that transmission providers should be required to demonstrate that all stakeholders are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term Regional Transmission Planning.[1990]

898. PPL stresses the important role that states play in siting transmission facilities and the significance of benefits from transmission facilities in this process, cautioning that differences between states' and the Commission's delineation and evaluation of benefits will result in great uncertainty. PPL asserts that this uncertainty could lead to abandoned projects, costly litigation, and a largely underutilized planning tool, akin to transmission projects driven by public policy needs under Order No. 1000.[1991]

899. In contrast, ACORE notes that the benefits of transmission facilities are often spread out among states regardless of the state policies contributing to the need for such transmission facilities.[1992]

900. SoCal Edison urges the Commission not to decouple policy projects from reliability and economic projects in transmission planning, so as to reduce barriers to regional coordination and ensure analysis of all potential benefits of a transmission project.[1993]

901. Indiana Commission states that it supports the NOPR proposal as long as the final order provides for an equitable cost allocation method that allocates costs to the cost causer and beneficiaries of regional transmission development.[1994]

c. Commission Determination

902. Consistent with the NOPR, we continue to decline to define ''benefits'' or ''beneficiaries.'' We discuss above descriptions of the seven required benefits, and we further require transmission providers to propose a method to measure each of those benefits. These descriptions and requirements for these seven benefits will facilitate transparency regarding the use of benefits in Long-Term Regional Transmission Planning and represent an improvement in this respect over Order No. 1000, which lacked such descriptions.[1995] However, we do not believe that establishing a definition of ''benefits'' or ''beneficiaries'' would significantly improve upon these descriptions and we are concerned that any such definition could inadvertently exclude benefits and beneficiaries.

903. We acknowledge comments requesting greater clarity regarding states' roles in determining benefits in their transmission planning regions and regarding the benefits that will be used by transmission providers in Long-Term Regional Transmission Planning, including NRECA's and Vermont State Entities' assertions that transmission providers should be required to demonstrate that all stakeholders (including state entities and load-serving entities) are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term Regional Transmission Planning.[1996] In response, we note this final order provides transmission providers with flexibility as to how they measure the seven required benefits, as well as flexibility to use additional benefits beyond the seven that we require. Consistent with other reforms in this final order incorporating an inclusive role for states in transmission planning, we encourage transmission providers to consult with states as they develop proposals to comply with the requirements of this final order and consider whether, and if so, how, to use additional benefits in Long-Term Regional Transmission Planning.[1997]

E. Evaluation and Selection of Long-Term Regional Transmission Facilities

1. Requirement To Adopt an Evaluation Process and Selection Criteria

a. NOPR Proposal

904. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a transparent and not unduly discriminatory evaluation process and criteria to identify and evaluate transmission facilities (or portfolios of transmission facilities) for potential selection that address transmission needs driven by changes in the resource mix and demand.[1998] The Commission preliminarily found that the development and analysis of Long-Term Scenarios cannot remedy the deficiencies in the Commission's existing regional transmission planning requirements without the inclusion of such an evaluation process and selection criteria because, without them, transmission providers' Commission-jurisdictional rates may be unjust and unreasonable and unduly discriminatory and preferential.[1999]

905. The Commission further proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

b. Comments

906. Many commenters support the Commission's proposal to require

[1985] Virginia Commission Staff Initial Comments at 5.

[1986] PJM Market Monitor Initial Comments at 4.

[1987] Michigan Commission Initial Comments at 7–8.

[1988] Massachusetts Attorney General Initial Comments at 14.

[1989] NYISO Initial Comments at 37; NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

[1990] NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

[1991] PPL Initial Comments at 14–15.

[1992] ACORE Initial Comments at 12; ACORE Reply Comments at 6.

[1993] SoCal Edison Initial Comments at 12–13.

[1994] Indiana Commission Initial Comments at 6–7.

[1995] As noted above, we do not require transmission providers to include additional benefits that they use for purposes of evaluation and selection of Long-Term Regional Transmission Facilities in their OATTs.

[1996] NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

[1997] *See supra* Other Benefits section.

[1998] *See* NOPR, 179 FERC ¶ 61,028 at PP 241–242.

[1999] *Id.* P 250.

transmission providers to include in their OATTs provisions providing criteria that they will use to identify and evaluate transmission facilities for potential selection to address transmission needs driven by changes in the resource mix and demand.[2000] For example, Pacific Northwest State Agencies argue that this reform is critical to ensuring that Long-Term Regional Transmission Planning results in appropriate modeling and evaluation of Long-Term Regional Transmission Facilities.[2001] ACEG contends that transparent selection processes are key to reducing conflict (including costly litigation), developing legally sustainable long-term regional transmission plans, and maximizing benefits over time to consumers without over-building transmission facilities.[2002]

907. Other commenters oppose the Commission's proposal. Many of these commenters argue that Long-Term Regional Transmission Planning should be for informational purposes only and that the Commission should not require transmission providers to include selection criteria in their OATTs.[2003] Alabama Commission contends that Long-Term Regional Transmission Planning should not involve selection or construction obligations unless the affected state regulators support such actions.[2004] ELCON argues that selection should occur in ''nearer-term planning (*i.e.*, 10–15 years)'' when there is greater certainty that there is a specific transmission need.[2005]

908. Some commenters argue that it is unnecessary for the Commission to require that transmission providers include additional selection criteria in their OATTs. For example, Dominion contends that Order No. 1000 already requires transmission providers to include selection criteria in their OATTs, and that the final order should allow, but not require, them to add to those existing selection criteria.[2006] Idaho Commission also believes that Order No. 1000's requirements are adequate and argues that the Commission has not demonstrated that there is a need to modify them.[2007] Similarly, Idaho Power argues that selection criteria specific to Long-Term Regional Transmission Planning are unnecessary in light of existing processes to identify and evaluate transmission facilities in the NorthernGrid transmission planning region.[2008] NYISO requests that the Commission confirm that the final order will not require changes to or the replacement of existing selection criteria.[2009] Chemistry Council argues that the Commission should affirm that transmission providers must continue addressing nearer-term regional transmission needs, giving significant weight to transmission facilities that meet customer and end-user needs, ensure grid reliability and energy security, and prevent abandonment of needed resources.[2010]

909. Clean Energy Buyers state that they support the NOPR proposal to grant eligibility to use the applicable cost allocation method to the developer of a Long-Term Regional Transmission Facility selected, subject to applicable development schedules. Clean Energy Buyers argue that this proposal could provide a more stable source of revenue and help resolve the ''first-mover problem,'' which in turn could support additional transmission development.[2011]

910. Finally, SPP contends that allowing transmission providers to include selection criteria in business practice manuals rather than their OATTs would give them more flexibility if they need to adjust study approaches.[2012]

c. Commission Determination

911. We adopt the NOPR proposal to require transmission providers in each transmission planning region to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs. We set forth requirements with respect to the evaluation process and selection criteria in the following sections.

912. We also adopt the NOPR proposal that, consistent with Order No. 1000, the transmission developer of a Long-Term Regional Transmission Facility that is selected, whether incumbent or nonincumbent, will be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

913. As explained above, transmission providers currently are not identifying or evaluating Long-Term Regional Transmission Facilities that might more efficiently or cost-effectively address Long-Term Transmission Needs and, therefore, do not have the opportunity to select such transmission facilities. We find that remedying these deficiencies in the Commission's existing regional transmission planning requirements requires the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities, as outlined below, which, together with other aspects of this final order, will help to ensure that transmission providers' Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

914. We find that the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities is essential to the reforms that we adopt in this final order. Without these essential components, Long-Term Regional Transmission Planning would merely inform the existing regional transmission planning processes rather than solving the deficiencies in the Commission's existing regional transmission planning requirements that we identify in this final order. The complete set of reforms that we adopt here are fundamental to resolving these deficiencies and to ensuring that transmission providers have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs. Therefore, we disagree with commenters who suggest that an evaluation process or selection criteria are unnecessary or

[2000] ACEG Initial Comments at 9; ACORE Initial Comments at 14; Amazon Initial Comments at 9; Ameren Initial Comments at 20; APPA Initial Comments at 33; CARE Coalition Initial Comments at 11–12; Clean Energy Buyers Initial Comments at 22; Exelon Initial Comments at 17; GridLab Initial Comments at 19; NRECA Initial Comments at 25; Ørsted Initial Comments at 5–6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 18; Resale Iowa Initial Comments at 7–8.

[2001] Pacific Northwest State Agencies Initial Comments at 19.

[2002] ACEG Initial Comments at 9, 58.

[2003] Alabama Commission Initial Comments at 3; ELCON Initial Comments at 10; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23–24; NRG Initial Comments at 6, 14; Ohio Consumers Initial Comments at 20; *see also* NARUC Initial Comments at 5 (''Long-Term Regional Transmission Planning [should] be used as a planning tool and not a construction requirement.''); TANC Initial Comments at 10 (commenting that TANC ''requests that the Commission clarify[ ] that the Commission is not proposing to require use of a 20-year planning horizon for . . . selecting Long-Term Regional Transmission Facilities'').

[2004] Alabama Commission Initial Comments at 3. Relatedly, Avangrid argues that the Commission should more clearly articulate how selection affects the actual construction of the transmission facility. Avangrid Initial Comments at 17.

[2005] ELCON Initial Comments at 10–11.

[2006] Dominion Initial Comments at 37 (citing NOPR, 179 FERC ¶ 61,028 at P 236).

[2007] Idaho Commission Initial Comments at 4–5.

[2008] Idaho Power Initial Comments at 8.

[2009] NYISO Initial Comments at 43.

[2010] Chemistry Council Initial Comments at 6–7.

[2011] Clean Energy Buyers Initial Comments at 21–22 (citing NOPR, 179 FERC ¶ 61,028 at P 247).

[2012] SPP Initial Comments at 21–22.

inappropriate for the Long-Term Regional Transmission Planning[2013] reforms that we adopt in this final order.

915. We understand that transmission providers might propose to re-purpose existing evaluation processes or selection criteria (with or without modifications thereto) to use in Long-Term Regional Transmission Planning. In their compliance filings, transmission providers must propose the evaluation process and selection criteria that they will use in Long-Term Regional Transmission Planning, and they must demonstrate that they meet the final order requirements. In response to NYISO's request,[2014] however, we clarify that nothing in this final order requires transmission providers to modify or replace selection criteria used in their existing reliability and economic Order No. 1000 regional transmission planning processes.

916. As discussed below, to meet the requirements of this final order, transmission providers in each transmission planning region must establish a Long-Term Regional Transmission Planning evaluation process that: (1) identifies Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs; (2) measures the benefits of the identified Long-Term Regional Transmission Facilities consistent with the final order requirements; and (3) designates a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[2015] We recognize the inherent uncertainty involved in identifying Long-Term Transmission Needs over the minimum transmission planning horizon adopted in this final order and in measuring the benefits that could be provided by Long-Term Regional Transmission Facilities. However, we continue to believe that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that minimize these risks while allowing for selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet Long-Term Transmission Needs. We emphasize that we do not require transmission providers to select any particular Long-Term Regional Transmission Facilities but rather to adopt an evaluation process and selection criteria that meet the final order requirements. This evaluation process will ensure that Long-Term Regional Transmission Planning will provide transmission providers with a framework that allows for the selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.[2016]

917. We reiterate that, consistent with Order No. 1000,[2017] selection in the regional transmission plan does not entitle the transmission developer of a selected Long-Term Regional Transmission Facility to site or construct that transmission facility, nor does it obviate the need for the transmission developer to obtain other state, local, and/or Federal permits or authorizations. For this reason, we disagree with comments suggesting that the Commission proposed to do otherwise in the NOPR.[2018]

918. Finally, we find that, consistent with the Commission's rule of reason,[2019] transmission providers' evaluation processes and selection criteria significantly affect rates, are reasonably susceptible to specification, and are not otherwise so generally understood as to render their recitation superfluous and therefore must be included in their OATTs. As such, we reject SPP's request that we allow transmission providers to instead maintain evaluation processes and selection criteria in their business practice manuals.[2020]

2. Flexibility

a. NOPR Proposal

919. Subject to certain minimum requirements, the Commission proposed in the NOPR to provide transmission providers with the flexibility to propose the selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective regional transmission facilities to address the region's transmission needs driven by changes in the resource mix and demand ultimately are selected.[2021] The Commission stated that this proposed flexibility would help accommodate regional differences, such as differences in transmission needs, factors driving those needs, and market structures.[2022] The Commission stated that providing flexibility to propose evaluation processes and selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.[2023] The Commission stated that it further believed this proposed flexibility would allow transmission providers in each transmission planning region to develop selection criteria that could sufficiently balance individual state interests within each transmission planning region.[2024]

b. Comments

920. Many commenters support the Commission's proposal to provide transmission providers with the flexibility to propose an evaluation process and selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities to address the transmission planning region's transmission needs driven by changes in the resource mix and demand ultimately are selected.[2025]

[2013] *See, e.g.,* Alabama Commission Initial Comments at 3; Dominion Initial Comments at 37; ELCON Initial Comments at 10–11; Idaho Commission Initial Comments at 4–5; Idaho Power Initial Comments at 8; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23–24; NRG Initial Comments at 6, 14; TANC Initial Comments at 10; *see also* Ohio Consumers Initial Comments at 20 (arguing that a 20-year transmission planning horizon is inappropriate for constructing or allocating the costs of transmission facilities).

[2014] NYISO Initial Comments at 43. We reiterate that, as discussed above in the Participation in Long-Term Regional Transmission Planning section, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements, provided that transmission providers demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final order.

[2015] *See, e.g.,* NOPR, 179 FERC ¶ 61,028 at P 56 (setting forth requirements for Long-Term Regional Transmission Planning).

[2016] For these reasons, in addition to those discussed above, we disagree with ELCON that transmission providers should only select transmission facilities in ''near-term planning (*i.e.,* 10–15 years).'' ELCON Initial Comments at 10–11.

[2017] *E.g.,* Order No. 1000–A, 139 FERC ¶ 61,132 at P 191.

[2018] *See, e.g.,* Alabama Commission Initial Comments at 3; Dominion Reply Comments at 8 (citing PIOs Initial Comments at 28; NARUC Initial Comments at 5–6, 39); NARUC Initial Comments at 5, 39.

[2019] *See Cal. Indep. Sys. Operator Corp.,* 185 FERC ¶ 61,210, at P 183 (2023) (citing *Hecate Energy Greene Cnty. 3 LLC* v. *FERC,* 72 F.4th 1307, 1314 (D.C. Cir. 2023); *City of Cleveland* v. *FERC,* 773 F.2d 1368, 1376 (D.C. Cir. 1985)).

[2020] SPP Initial Comments at 21–22.

[2021] NOPR, 179 FERC ¶ 61,028 at P 242.

[2022] *Id.* P 243.

[2023] *Id.* P 243.

[2024] *Id.* P 244.

[2025] APPA Initial Comments at 33–34; Avangrid Initial Comments at 17; California Commission Initial Comments at 37; Chemistry Council Initial Comments at 6; Duke Initial Comments at 26; Eversource Initial Comments at 26; GridLab Initial Comments at 19; ISO–NE Initial Comments at 35;

921. For example, Nebraska Commission asserts that this flexibility will allow transmission providers to develop selection criteria that balance individual states' interests.[2026] Eversource argues that flexibility will foster investments in cost-effective regional transmission facilities, accommodate differences in transmission needs between transmission planning regions, and encourage stakeholder engagement.[2027] While NEPOOL supports flexibility as a general matter, it asserts that the Commission should articulate guiding principles for how selection decisions will be made and by whom, and guidelines regarding when transmission solutions should be selected to address long-term transmission needs.[2028]

922. By contrast, some commenters argue that the Commission should establish *pro forma* selection criteria.[2029] Clean Energy Associations argues that doing so would enhance transparency, minimize differences across seams, and enable state regulators, consumers, and other market participants to evaluate transmission projects that result from Long-Term Regional Transmission Planning on an apples-to-apples basis.[2030] Similarly, SEIA urges the Commission to establish a set of minimum requirements for selecting transmission facilities in Long-Term Regional Transmission Planning, arguing that transmission planning regions otherwise may fail to select transmission facilities that provide significant regional benefits.[2031] For its part, Clean Energy Buyers contends that adopting *pro forma* selection criteria would provide greater transparency and consistency across transmission planning regions, hopefully help to avoid disputes, and allow for consultation with states and other stakeholders.[2032]

923. Acadia Center and CLF argue that requiring a minimum set of selection criteria will provide critical information to transmission providers who rely on the Commission to make clear what considerations they may weigh in Long-Term Regional Transmission Planning, facilitating more productive conversations at the regional level.[2033]

c. Commission Determination

924. Subject to the requirements described further below, we adopt the NOPR proposal to require transmission providers in each transmission planning region to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria, that they believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address the transmission planning region's Long-Term Transmission Needs. We believe that providing transmission providers with this flexibility will allow them to design evaluation processes and selection criteria that can accommodate regional differences.

925. We reject requests that, instead of providing transmission providers with flexibility, we set forth standard evaluation processes and selection criteria in this final order that transmission providers would be required to adopt.[2034] While we recognize that there may be some benefits to doing so, we also find that transmission planning regions have different transmission needs and market structures that make designing a standard evaluation process and selection criteria difficult.

926. In response to NEPOOL,[2035] we clarify that transmission providers make the selection decisions in Long-Term Regional Transmission Planning. Although we do not require transmission providers to select any particular Long-Term Regional Transmission Facility to address Long-Term Transmission Needs, as discussed below in the No Selection Requirement section, we do set forth minimum requirements with respect to the evaluation process and selection criteria, which will help to ensure that transmission providers select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address Long-Term Transmission Needs.

3. Minimum Requirements

a. NOPR Proposal

927. In the NOPR, the Commission proposed certain minimum requirements such that transmission providers' selection criteria must (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.[2036] The Commission noted that, to comply with the Order Nos. 890 and 1000 transmission planning principles, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.[2037] The Commission stated that the evaluation process and, specifically, the selection criteria, must seek to maximize benefits to consumers over time without over-building transmission facilities.[2038]

928. The Commission stated that providing flexibility to propose selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.[2039] The Commission also stated that transmission providers would have the flexibility to propose to use a portfolio approach in selecting regional transmission facilities that address transmission needs driven by changes in the resource mix and demand.[2040] The Commission proposed to require transmission providers that propose such an approach to include in their OATTs provisions describing whether the selection criteria would apply to one proposed regional transmission facility or to a portfolio of regional transmission facilities, as well as whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in

MISO Initial Comments at 54; Nebraska Commission Initial Comments at 8; TAPS Initial Comments at 16; US Chamber of Commerce Initial Comments at 8.

[2026] Nebraska Commission Initial Comments at 8 (citing NOPR, 179 FERC ¶ 61,028 at P 244).

[2027] Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at PP 242–243).

[2028] NEPOOL Initial Comments at 7–8.

[2029] *See, e.g.,* ACORE Reply Comments at 5–6 (citing Policy Integrity Initial Comments at 2–3); Policy Integrity Initial Comments at 2–3.

[2030] Clean Energy Associations Initial Comments at 22–23.

[2031] SEIA Initial Comments at 5, 19.

[2032] Clean Energy Buyers Initial Comments at 22–23.

[2033] Acadia Center and CLF Initial Comments at 10–11.

[2034] Acadia Center and CLF Initial Comments at 10–11; Clean Energy Associations Initial Comments at 22–23; SEIA Initial Comments at 5, 19.

[2035] NEPOOL Initial Comments at 8.

[2036] NOPR, 179 FERC ¶ 61,028 at PP 241–242, 245.

[2037] *Id.* P 242 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328).

[2038] *Id.*

[2039] *Id.* P 243.

[2040] *Id.* P 249.

the resource mix and demand or would be used only in certain specified instances.[2041]

929. The Commission recognized the inherent uncertainty involved in predicting future transmission needs, including those driven by changes in the resource mix and demand, as well as the concerns that many commenters expressed in response to the ANOPR that imperfect information may lead to selecting transmission facilities that become stranded assets.[2042] The Commission also stated that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that could minimize these risks while allowing for investment in transmission facilities that more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand.[2043] The Commission noted that under a ''least-regrets'' approach, for example, transmission providers in a transmission planning region would select a transmission facility (or portfolio of transmission facilities) that is net-beneficial in most or all Long-Term Scenarios, even if other transmission facilities have more net benefits or a higher benefit-cost ratio in a single Long-Term Scenario. The Commission stated that another approach is a ''weighted-benefits approach,'' in accordance with which transmission providers in a transmission planning region would select a transmission facility (or portfolio of regional transmission facilities) based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario studied.[2044]

b. Comments

930. Commenters make a wide variety of arguments with respect to the minimum requirements that the Commission should impose with respect to evaluation processes and selection criteria. Many commenters support the Commission's proposal to require that selection criteria: (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.[2045]

931. Some commenters generally support the Commission's proposal with certain modifications. For example, Ameren argues that requiring selection criteria to maximize benefits to consumers over time without over-building transmission facilities is highly subjective, because such a requirement could refer to maximizing gross or net benefits and because certain interpretations could override the consideration of costs.[2046] Vistra likewise argues that the directive to maximize benefits to consumers over time without over-building transmission facilities is unhelpfully vague and that maximizing benefits should not be understood to disregard costs.[2047] WATT Coalition states that the Commission should require maximization of net benefits and cautions that it would be unjust and unreasonable to ignore benefits or costs in the assessment of options.[2048]

932. GridLab argues that selection criteria should seek to manage uncertainty and risk, stating that the Commission should clarify that the criteria must address not only the risk of over-building but also of under-building transmission.[2049] In contrast, New York State Department argues that selection criteria should be designed to minimize the financial risk to ratepayers of over-building the transmission system.[2050] NYISO requests clarification on the definition of over-building and argues that the final order should provide additional guidance on how transmission planning regions should address this risk. NYISO contends that the final order should treat the risk of over-building as an additional qualitative criterion that transmission planning regions should consider, as informed by open and transparent stakeholder review.[2051]

933. EEI contends that it is appropriate for the Commission to provide guidance by providing non-mandatory factors for transmission planning regions to consider.[2052] ELCON argues that transparency with respect to selection criteria requires that the criteria and their proper weighting must be clear and easily accessible to consumers through transmission providers' OASIS and OATT.[2053]

934. Commenters make several arguments with respect to the metrics that the Commission should allow or require transmission providers to use when evaluating whether to select Long-Term Regional Transmission Facilities. For example, some commenters argue that transmission providers should select transmission facilities by using metrics that seek to maximize net benefits instead of ones that rely on benefit-cost ratios.[2054] ACEG argues that the Commission can require metrics that seek to maximize net benefits using the same authority it relied upon in promulgating Order No. 1000.[2055]

935. Breakthrough Energy states that, while metrics such as benefit-cost ratios are useful indicators, the efficient solution is the one that maximizes net benefits.[2056] WATT Coalition contends that, in Australia, the transmission planner lists all transmission facility alternatives ranked by the net present value of the consumer benefits that the alternatives would provide, and selects the option that provides the most benefits in the absence of a compelling reason not to do so.[2057]

936. MISO argues that selection criteria should maximize long-term transmission value, defined as the difference between total benefits and total costs on a present value basis over a pre-determined transmission planning horizon.[2058] MISO contends that using such a metric is important when benefit-cost ratios are high and transmission expansion is substantial, as many of the benefits provided by new transmission facilities are difficult to quantify in terms of dollars despite providing significant qualitative benefits.[2059] Relatedly, CTC Global argues that selecting transmission facilities with the lowest capital costs is no longer a best

[2041] *Id.*

[2042] *Id.* P 251.

[2043] *Id.*

[2044] *Id.* (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60).

[2045] *See* ACEG Initial Comments at 58–59; ACORE Initial Comments at 14; Amazon Initial Comments at 9; APPA Initial Comments at 33–34; CARE Coalition Initial Comments at 11–12; NESCOE Initial Comments at 46; NRECA Initial Comments at 25; Ørsted Initial Comments at 5–6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 17–18; TAPS Initial Comments at 16.

[2046] Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at P 243 n.390).

[2047] Vistra Initial Comments at 17–18.

[2048] WATT Coalition Initial Comments at 9.

[2049] GridLab Initial Comments at 19.

[2050] New York State Department Initial Comments at 4.

[2051] NYISO Initial Comments at 43.

[2052] EEI Initial Comments at 45–46.

[2053] ELCON Initial Comments at 17.

[2054] ACEG Initial Comments at 49–50; Breakthrough Energy Initial Comments at 23; Clean Energy Associations Initial Comments at 22; DC and MD Offices of People's Counsel Initial Comments at 33; Evergreen Action Initial Comments at 4; ITC Initial Comments at 25; WATT Coalition Initial Comments at 9.

[2055] *See* ACEG Initial Comments at 49–50 (citing *S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d at 58).

[2056] Breakthrough Energy Initial Comments at 23.

[2057] WATT Coalition Initial Comments at 9.

[2058] MISO Initial Comments at 55–56.

[2059] *Id.*

practice, in light of increased debate in many RTOs/ISOs about issues such as mandated resource mixes, compensation in capacity markets, transmission planning criteria and cost allocation, and carbon taxes.[2060] CTC Global asserts that, if a transmission project is selected with least capital cost as a selection criterion, consumers will pay higher energy costs and higher total costs than what they would pay if the Commission were to require transmission providers to evaluate the NOPR's proposed benefits as well as cost.[2061]

937. Commenters also offer a variety of perspectives regarding benefit-cost ratios. Clean Energy Associations recommend that, if the Commission continues to allow benefit-cost ratios, such ratios not exceed Order No. 1000's maximum allowable benefit-cost ratio of 1.25-to-1.00.[2062] ITC argues that, if the Commission allows transmission providers to use benefit-cost ratios, it should require the use of a 1.00-to-1.00 benefit-cost ratio for the evaluation of candidate portfolios.[2063] Cypress Creek asserts that the Commission should retain the maximum permitted benefit-cost ratio of 1.25-to-1.00 and consider lowering that threshold to 1.00-to-1.00 because a transmission facility with a benefit-cost ratio of at least 1.00-to-1.00 is beneficial.[2064]

938. Pattern Energy argues that the existing maximum 1.25-to-1.00 allowable benefit-cost ratio is too high for purposes of Long-Term Regional Transmission Planning. Pattern Energy explains that scenarios and sensitivities typically are created to bookend what the future may look like, and those bookends are often weighted lower than a ''business as usual'' scenario. In this context, Pattern Energy argues that a lower benefit-to-cost ratio is necessary because the standard to approve transmission facilities is so high that transmission ratepayers are not receiving an appropriate opportunity to realize the value of new transmission infrastructure. Pattern Energy suggests that a more reasonable benefit-cost ratio would be 1.10-to-1.00 but notes that a higher benefit-to-cost ratio may be appropriate to evaluate a portfolio of transmission facilities (*e.g.,* 1.15–1.25).[2065]

939. By contrast, New York State Department asserts that transmission providers should not select a transmission facility unless benefits in the long term greatly exceed costs and that adopting a much higher benefit-cost ratio than the existing 1.25 standard may be required (*e.g.,* 2.25-to-1.00).[2066]

940. Some commenters express support for least-regrets[2067] or weighted-benefits approaches[2068] to selecting transmission facilities in Long-Term Regional Transmission Planning. For example, National Grid argues that identifying least-regrets transmission facilities should be the goal of Long-Term Regional Transmission Planning.[2069]

941. Avangrid explains that ''no regrets'' or ''low regrets'' transmission facilities are those that likely will be needed under multiple scenarios and a broad range of assumptions.[2070] PG&E agrees and argues that these transmission facilities are most likely to realize projected benefits.[2071] PG&E states that transmission facilities that provide more limited benefits or benefits under a limited number of scenarios may require additional study and should not be selected until there is more certainty that their benefits will be realized.[2072]

942. Exelon also advocates for a least-regrets approach, arguing that it minimizes risk and maximizes value for customers and transmission owners.[2073] Eversource contends that a least-regrets approach is most likely to build the consensus among stakeholders that can support transmission facilities through planning, financing, siting, and cost allocation.[2074] NRECA argues that a least-regrets approach will help mitigate the risk that consumers will pay for unnecessary transmission facilities.[2075]

943. ACORE recommends the use of a weighted-benefits approach, which ACORE argues has been endorsed in recent expert reports on transmission planning.[2076] Dominion sees promise in both least-regrets and weighted-benefits approaches but argues that requiring transmission providers to propose specific selection criteria may result in litigation, delay, and increased costs.[2077]

944. New England for Offshore Wind argues that the Commission should require transmission providers to give preference to transmission facilities that perform well under a range of scenarios.[2078] A number of commenters caution, however, that the Commission should allow transmission providers to select transmission facilities even where they are not net-beneficial in every Long-Term Scenario.[2079]

945. A number of commenters recommend accounting for siting considerations in various ways in the selection of transmission facilities. For example, CARE Coalition recommends that the Commission require transmission providers to work with state authorities and other stakeholders to develop environmental- and energy justice-based siting criteria to guide transmission project selection and cost allocation.[2080] CARE Coalition also states that the Commission should allow RTOs/ISOs to take a flexible approach to identifying siting-based criteria that consider local and regional impacts, local and regional energy justice impacts (including use of existing transmission corridors and investment flow to disadvantaged communities as defined by the President's Justice40 Initiative), integration with plans for energy storage, and integration with major infrastructure development plans (*e.g.,* highways, rail corridors).[2081] CARE Coalition states that planners and stakeholders should consider the

[2060] CTC Global Initial Comments at 6–7 (citing *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225 (2021) (Christie, Comm'r, concurring at PP 4–5)).

[2061] *Id.* at 9.

[2062] Clean Energy Associations Initial Comments at 22.

[2063] ITC Initial Comments at 25–26.

[2064] *See* Cypress Creek Reply Comments at 8 & n.14 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 646).

[2065] Pattern Energy Initial Comments at 14–15.

[2066] New York State Department Initial Comments, Montalvo Aff. at 14–15.

[2067] *See* Avangrid Initial Comments at 10–11; Eversource Initial Comments at 26–27; Exelon Initial Comments at 18; GridLab Initial Comments at 19–20; National Grid Initial Comments at 11–12; NRECA Initial Comments at 48; PG&E Initial Comments at 6.

[2068] *See* ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60; Derek Stenclik and Ryan Deyoe, *Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force,* Energy Systems Integration Group, 37 (June 2022), *https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf*) (Energy Systems Integration Group June 2022 Report)); Clean Energy Associations Initial Comments at 22 (citing NOPR, 179 FERC ¶ 61,028 at P 251).

[2069] National Grid Initial Comments at 11–12 (citing National Grid ANOPR Initial Comments at 16).

[2070] Avangrid Initial Comments at 10–11.

[2071] PG&E Initial Comments at 6.

[2072] *Id.*

[2073] Exelon Initial Comments at 18.

[2074] Eversource Initial Comments at 26–27.

[2075] NRECA Initial Comments at 48.

[2076] ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60; Energy Systems Integration Group June 2022 Report at 37).

[2077] *See* Dominion Initial Comments at 38.

[2078] New England for Offshore Wind Initial Comments at 2; *see also* Clean Energy Associations Initial Comments at 22 (arguing for selecting transmission facilities that maximize net benefits across multiple scenarios).

[2079] ACEG Initial Comments at 7, 30; ACORE Initial Comments at 14; Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 37–38.

[2080] CARE Coalition Initial Comments at 7–8.

[2081] *Id.* at 10.

economic, environmental, and other impacts associated with the full expected useful lives of proposed transmission and associated facilities.[2082]

946. Similarly, ACEG recommends selection criteria that account for whether potential transmission facilities use existing rights-of-way, contribute to equitable energy service, alleviate environmental justice concerns, or impact employment and economic development.[2083] Exelon also recommends giving preference to approaches that prioritize existing rights-of-way, given that they are more readily accomplished and have fewer environmental impacts than greenfield transmission projects.[2084]

947. Acadia Center and CLF urge the Commission to provide transmission providers clear guidance, by adopting minimum selection criteria in the final order, on their ability to consider factors such as environmental justice, mitigating environmental impacts, use of existing transmission facilities, and non-transmission alternatives, which have community and environmental benefits. Acadia Center and CLF contend that the consideration of these issues is consistent with NEPA, the FPA, and state law, and that, in the absence of such guidance, transmission providers may continue to exclude consideration of these issues given concerns regarding their authority and jurisdiction to do so.[2085] Grand Rapids NAACP also argues that the Commission has the authority to require that transmission providers explicitly incorporate energy equity and justice concerns into selection criteria, and that the Commission should do so in a final order.[2086] WE ACT states that equity considerations and other non-energy benefits (*e.g.,* pollution reduction, health, jobs, and local economic development) should be among the benefits that transmission providers could use in selecting transmission facilities.[2087] PIOs assert that the Commission should require transmission providers to consider equity impacts when determining which transmission facilities to select, including whether construction of such facilities will impact environmental justice communities and what the cumulative impacts of the facilities will be.[2088]

948. DC and MD Offices of People's Counsel suggest that transmission providers should select transmission facilities that optimize the interconnection of portfolios of generation resources, including those that deliver benefits arising from grid decarbonization and the benefits set forth in the NOPR.[2089] Eversource argues that the Commission should consider requiring transmission providers to address needs identified in high-impact, low-frequency event scenarios, such that selection criteria would accommodate worst-case scenarios like Winter Storm Uri.[2090] Exelon urges that selection criteria be tied to well-established and defined needs, like reliability and market economics, such as reduced production costs, congestion, or capacity costs.[2091]

949. Duke asserts that selection of a transmission facility in the absence of clear consensus from load-serving entities, states, and/or customers would be problematic and thwart the Commission's objectives, especially where certain transmission facilities will not be supported by state commissions in siting decisions or by consumer advocates in cost recovery proceedings.[2092] As such, Duke argues that the Commission should allow transmission providers to include a qualitative selection criterion of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of facilities.[2093] New York TOs state that New York Commission should retain its flexibility under NYISO's public policy transmission planning process such that, when the New York Commission identifies a transmission need driven by Public Policy Requirements, it can also require certain selection criteria in addition to those in NYISO's OATT.[2094]

950. NYISO contends that the final order should continue to allow transmission providers to use a range of qualitative and quantitative criteria to rank and select transmission projects as the more efficient or cost-effective transmission facility.[2095] ACEG encourages the Commission to provide guidance in the final order as to selection criteria that meet its requirements, arguing that doing so would facilitate efficient compliance proceedings.[2096]

951. Maine Public Advocate also argues that the Commission should require transmission providers to select non-transmission alternatives when they meet an identified transmission need at the same or lower cost.[2097]

952. TAPS asserts that the Commission should require transmission providers to explain how their selection criteria would account for the uncertainty involved in predicting future transmission needs and to report ''Affordability Metrics'' that disclose the impact that selection of a particular transmission facility would have on transmission rates.[2098] TAPS argues that these ''Affordability Metrics'' would enhance the transparency of stakeholder processes in Long-Term Regional Transmission Planning and assist states in discussions about cost allocation and in considering whether to voluntarily fund a particular transmission facility or portfolio of transmission facilities.[2099]

953. ELCON states that, given the potential for massive transmission investment in the next 10 to 25 years, it is vitally important that consumers be protected from any unnecessary costs.[2100] As such, ELCON argues that selection criteria must incorporate metrics for reliability and economic efficiency, incorporate all potential drivers of transmission needs, and afford greater weight to those transmission facilities that produce benefits in more than one category.[2101]

[2082] *Id.*

[2083] ACEG Initial Comments at 59.

[2084] Exelon Initial Comments at 18.

[2085] Acadia Center and CLF Initial Comments at 11–12.

[2086] Grand Rapids NAACP Initial Comments at 17–23 (citations omitted).

[2087] WE ACT Initial Comments at 5.

[2088] PIOs Reply Comments at 17 (citations omitted).

[2089] DC and MD Offices of People's Counsel Initial Comments at 38–39.

[2090] Eversource Initial Comments at 26–27 (citing FERC, North American Electric Reliability Corporation, Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas, and the South-Central United States* (Nov. 2021), *https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and*).

[2091] Exelon Initial Comments at 18.

[2092] Duke Initial Comments at 26–27.

[2093] *Id.* at 4, 26–27.

[2094] New York TOs Initial Comments at 9, 11–12, 15.

[2095] NYISO Initial Comments at 39–40.

[2096] ACEG Initial Comments at 59.

[2097] Maine Public Advocate Initial Comments at 1–2.

[2098] TAPS Initial Comments at 16–17.

[2099] *Id.* at 19–20 (citing Alliant Energy, et al., ANOPR Initial Comments at 14; Alliant Energy, et al., ANOPR Reply Comments at 2–3).

[2100] ELCON Initial Comments at 16 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* Net Zero America, 108 (Oct. 29, 2021), *https://www.dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20%2829Oct2021%29.pdf?dl=0*).

[2101] *Id.*

c. Commission Determination

i. Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities

954. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to propose evaluation processes, including selection criteria, that are transparent and not unduly discriminatory. Consistent with Order No. 1000,[2102] we adopt the NOPR proposal to establish a requirement that transmission providers' evaluation of transmission facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. As discussed further below, we modify the NOPR proposal to include a requirement that the determination of why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected must include the measured benefits for each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) considered in the Long-Term Regional Transmission Planning process.

955. We also adopt the NOPR proposal, with modification, to require transmission providers to propose on compliance evaluation processes, including selection criteria, that aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs. We modify the NOPR proposal to provide additional clarity as to how transmission providers' evaluation processes must aim to ensure the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs by adopting several requirements. First, transmission providers in a transmission planning region must identify one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that address the Long-Term Transmission Needs that the transmission providers have identified through Long-Term Regional Transmission Planning. As part of this identification, consistent with Order Nos. 890 and 1000,[2103] nonincumbent transmission developers must be able to propose transmission facilities in Long-Term Regional Transmission Planning. Thus, we clarify that transmission providers in each transmission planning region must make clear in their OATTs the point in the Long-Term Regional Transmission Planning evaluation process at which they will accept Long-Term Regional Transmission Facility proposals from stakeholders, including nonincumbent transmission developers. Second, transmission providers' evaluation processes must estimate the costs and measure the benefits of the Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are identified or proposed for potential selection, in addition to evaluating the identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities) using any qualitative or other quantitative selection criteria that the transmission providers in a transmission planning region propose to apply. Third, transmission providers must designate a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).[2104] This point must be no later than three years following the beginning of the Long-Term Regional Transmission Planning cycle.[2105] Finally, the evaluation process must culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. We reiterate, however, that, as discussed further below in the No Selection Requirement section, this final order does not require transmission providers to select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) to address Long-Term Transmission Needs.

956. As discussed earlier, this final order requires transmission providers to develop and use at least three Long-Term Scenarios, and one sensitivity analysis applied to each Long-Term Scenario, when conducting Long-Term Regional Transmission Planning. Each Long-Term Scenario or sensitivity analysis may suggest that different Long-Term Transmission Needs exist, that different Long-Term Regional Transmission Facilities would resolve those needs, or that such Long-Term Regional Transmission Facilities would provide different benefits for transmission customers. We clarify that, in the context of Long-Term Regional Transmission Planning, Order No. 890's requirements that transmission providers conduct coordinated, open, and transparent transmission planning on the regional level[2106] requires that transmission providers make transparent the methods that they used to analyze each individual Long-Term Scenario and the sensitivity or sensitivities applied to each scenario to determine the Long-Term Transmission Needs that exist in the transmission planning region, the Long-Term Regional Transmission Facilities that would resolve those needs, and the benefits of those Long-Term Regional Transmission Facilities for purposes of selection.[2107]

957. Consistent with the Order No. 1000 regional transmission planning requirements,[2108] the Long-Term Regional Transmission Planning process must result in a regional transmission plan that identifies the Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet the transmission planning region's Long-Term Transmission Needs. To effectuate this requirement, we clarify that transmission providers have an affirmative obligation to identify Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, regardless of whether any stakeholder proposes potential Long-Term Regional Transmission Facilities for consideration in Long-Term Regional Transmission Planning. In this section, we enumerate specific requirements for how transmission providers conduct their Long-Term Regional Transmission Planning with the aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities

[2102] Order No. 1000, 136 FERC ¶ 61,051 at P 328.

[2103] *See id.* P 315 (citing Order No. 890, 118 FERC ¶ 61,119 at P 494; Order No. 890–A, 121 FERC ¶ 61,297 at PP 215–216).

[2104] As described further below in the Voluntary Funding Opportunities section, transmission providers must also provide Relevant State Entities with the opportunity to fund the cost of, or part of the cost of, the Long-Term Regional Transmission Facility (or portfolio of such Facilities) to ensure that it meets the transmission providers' selection criteria.

[2105] We note, however, consistent with the discussion above in the Frequency of Long-Term Scenario Revisions section, that transmission providers may evaluate and select additional Long-Term Regional Transmission Facilities during the period of the Long-Term Regional Transmission Planning cycle after this point and before the commencement of the next such cycle.

[2106] Order No. 890, 118 FERC ¶ 61,119 at P 435.

[2107] For example, transmission providers might weigh specific Long-Term Scenarios and sensitivities based on the probability that the analyses reflect future system conditions (which the Commission referred to in the NOPR as a ''weighted-benefits approach''). NOPR, 179 FERC ¶ 61,028 at P 251 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60).

[2108] Order No. 1000, 136 FERC ¶ 61,051 at PP 55, 146–148; *see Louisville Gas & Elec. Co.,* 144 FERC ¶ 61,054, at PP 61–62 (2013), *on reh'g sub nom., Duke Energy Carolinas LLC,* 147 FERC ¶ 61,241, at PP 82–83 (2014).

are selected. By clearly enumerating their evaluation processes and selection criteria in their OATTs, transmission providers will provide significant transparency to stakeholders to understand how Long-Term Transmission Needs will be addressed, whether there are more efficient or cost-effective Long-Term Regional Transmission Facilities that may meet those needs, and their benefits.

958. Provided that transmission providers' evaluation processes and selection criteria comply with the requirements that we adopt here, we provide transmission providers with flexibility to determine how they will evaluate whether Long-Term Regional Transmission Facilities more efficiently or cost-effectively address Long-Term Transmission Needs, including by using benefit-cost ratios, assessing their net benefits and selecting the Long-Term Regional Transmission Facilities that maximize those benefits, and/or using some other method.[2109] Consistent with Order No. 1000 regional cost allocation principle (3), and as further discussed below in the Regional Transmission Cost Allocation section, transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[2110] We decline to reduce or increase the maximum benefit-cost ratio that transmission providers may use as a selection criterion in Long-Term Regional Transmission Planning. As the Commission found in Order No. 1000,[2111] requiring that a benefit-cost ratio, if adopted, not exceed 1.25-to-1.00 ensures that the ratio is not so high as to exclude Long-Term Regional Transmission Facilities with significant positive net benefits from selection.

959. We decline to require transmission providers to account for siting considerations in their evaluation process and selection criteria.[2112] We acknowledge that siting considerations (*e.g.,* use of existing rights-of-way) may affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility. While such siting considerations may inform the evaluation process and selection criteria, we do not require transmission providers to account for such considerations in this final order. We note, however, that, as discussed below in the Role of Relevant State Entities section, this final order requires that transmission providers consult with and seek the support of Relevant State Entities[2113] regarding the evaluation process and selection criteria that transmission providers propose to use to evaluate Long-Term Regional Transmission Facilities for selection.

960. We also do not require transmission providers to include environmental justice or equity considerations in their evaluation process or selection criteria. While several commenters recommend that we impose such requirements,[2114] none provides any approach for how these concerns would be incorporated into transmission providers' evaluation process and selection criteria on a generic basis. We acknowledge that the selection of Long-Term Regional Transmission Facilities represents a substantial step in the development of new electric transmission infrastructure, which may impact environmental justice communities or raise equity concerns. We further recognize that such environmental justice or equity considerations may affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility, particularly in regions where legal frameworks provide for consideration of environmental justice and equity. Nothing in this final order precludes transmission providers from proposing on compliance to include environmental justice considerations within their evaluation process and selection criteria.

961. NYISO requests that the Commission clarify that transmission providers may continue to use qualitative and quantitative measures in the Long-Term Regional Transmission Planning process.[2115] We clarify that nothing in this final order prohibits transmission providers from proposing to use qualitative factors in their evaluation processes and/or selection criteria. Accordingly, transmission providers may propose to use qualitative factors in their evaluation processes and/or qualitative selection criteria, provided that they demonstrate on compliance that their proposals comply with the evaluation process and selection criteria requirements of this final order.

962. In response to Duke's request to allow transmission providers to include a selection criterion that is a qualitative evaluation of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of such Facilities,[2116] we find that transmission providers may not include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Rather than address this issue via selection criteria regarding a *transmission provider's* anticipation of such an entity's response, we conclude that the requirement discussed below to consult with and seek support from Relevant State Entities regarding the evaluation process and selection criteria is a more appropriate mechanism to account for the Relevant State Entity's views. We also note that beyond this consultative process, state public utility commissions and consumer advocates have numerous opportunities to express their views on transmission development, including through state- and Commission-jurisdictional proceedings. Further, allowing such features in evaluation processes or selection criteria could amount to a requirement that transmission providers obtain the consent of Relevant State Entities, which, as discussed below in the Role of Relevant State Entities section, we do not believe is necessary or appropriate to resolve the deficiencies identified in this final order.[2117]

963. In response to New York TOs,[2118] we decline to require that transmission providers include selection criteria requested by state public utility commissions. As discussed further below in the Role of Relevant State Entities section, transmission providers must propose on compliance an evaluation process and selection criteria that comply with the

[2109] Nothing in this final order requires the use of any particular approach, and we clarify that transmission providers may use more than one approach complementarily. *Compare, e.g.,* MISO Initial Comments at 54–56 (explaining MISO's approach to selecting transmission facilities with the goal of maximizing ''long-term transmission value''), *with* MISO, FERC Electric Tariff, MISO OATT, attach. FF, Transmission Expansion Planning Protocol (90.0.0), sections II.B.1.c, II.C.2.b (setting forth as a minimum selection criterion a benefit-cost ratio of 1.25 or 1.00 for Market Efficiency Projects and Multi-Value Projects, respectively).

[2110] NOPR, 179 FERC ¶ 61,028 at P 243 n.390; Order No. 1000, 136 FERC ¶ 61,051 at P 646.

[2111] Order No. 1000, 136 FERC ¶ 61,051 at P 648.

[2112] CARE Coalition Initial Comments at 7–8; *see also* ACEG Initial Comments at 59; Exelon Initial Comments at 18.

[2113] Many Relevant State Entities exercise their state's authority over the siting of transmission facilities.

[2114] *See, e.g.,* Acadia Center and CLF Initial Comments at 11–12; Grand Rapids NAACP Initial Comments at 17–23 (citations omitted); PIOs Reply Comments at 17 (citations omitted).

[2115] NYISO Initial Comments at 39–40.

[2116] Duke Initial Comments at 4, 26–27.

[2117] *See New York* v. *FERC,* 535 U.S. at 26–28 (upholding Commission's decision not to assert jurisdiction over bundled retail transmission).

[2118] New York TOs Initial Comments at 9, 11–12, 15.

requirements of this final order after consulting with and seeking the support of Relevant State Entities. To the extent that a transmission provider believes that a selection criterion proposed by a Relevant State Entity would comply with the final order requirements, they may propose to include that criterion in their compliance filings, and the Commission will determine if it complies with these requirements.

ii. Maximize Benefits

964. We adopt the NOPR proposal, with modification, to require that transmission providers in each transmission planning region propose evaluation processes, including selection criteria, that seek to maximize benefits accounting for costs over time without over-building transmission facilities. In the NOPR, the Commission proposed that the evaluation processes and selection criteria seek to maximize benefits to consumers over time without over-building transmission facilities. However, we believe that it is appropriate to modify that proposal for clarity. We modify the requirement to require that transmission providers' evaluation processes and selection criteria seek to maximize benefits *accounting for costs.* Some commenters have interpreted the NOPR as proposing to allow transmission providers to disregard costs and simply maximize benefits.[2119] We clarify that was not the Commission's intent, and we modify the NOPR proposal in this final order to make that clear. Further, we note that while we omit reference ''to consumers'' in the requirement for brevity, we do not view this change as substantive. As discussed above, this requirement, together with other aspects of this final order, helps to ensure transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs in order to ensure just and reasonable Commission-jurisdictional rates, which ultimately benefits ratepayers.

965. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section, transmission providers conducting Long-Term Regional Transmission Planning must use and measure a set of benefits to evaluate Long-Term Regional Transmission Facilities. In setting forth an evaluation process and selection criteria, we clarify, consistent with the directive to seek to maximize benefits accounting for costs over time without over-building transmission facilities, that transmission providers may not disregard benefits that we require them to use and measure when implementing their approved evaluation process and selection criteria.[2120] We further clarify that transmission providers may not disregard benefits even where those benefits are only measured in certain transmission system conditions, such as may be the case with Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, and therefore are captured only under certain Long-Term Scenarios or sensitivities thereto. While transmission providers may not disregard such benefits, transmission providers' evaluation processes and selection criteria may account for the fact that certain benefits are only measured under certain conditions by, for example, weighting how likely certain conditions expressed in specific Long-Term Scenarios or sensitivities are to occur.

966. As discussed further below, transmission providers have the discretion to select or not select any Long-Term Regional Transmission Facility that they identify through Long-Term Regional Transmission Planning, even a facility that otherwise meets the selection criteria. However, as noted above, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected to address Long-Term Transmission Needs. We clarify that this determination must include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) evaluated by the transmission providers, whether or not the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[2121]

967. We acknowledge commenters' concerns that there is inherent uncertainty in Long-Term Regional Transmission Planning.[2122] This final order adopts provisions that allow for significant flexibility for transmission providers to address that uncertainty. As stated above in the Participation in Long-Term Regional Transmission Planning section, we require transmission providers to develop and use Long-Term Scenarios, which are a critical tool for managing uncertainty and facilitating regional transmission planning that account for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, transmission providers could adopt evaluation processes and selection criteria that would allow transmission providers to make selection decisions while minimizing the future risk of developing a previously selected Long-Term Regional Transmission Facility that is not the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. For example, transmission providers might develop a least-regrets approach under which they would select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation if those Long-Term Regional Transmission Facilities are net beneficial in more than one Long-Term Scenario and sensitivity analyses even if other transmission facilities have a higher benefit-cost ratio or provide more net benefits in a single Long-Term Scenario or particular sensitivity. Transmission providers might also adopt a weighted-benefits approach under which they would select a Long-Term Regional Transmission Facility based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario or sensitivity thereof that is studied. Under either approach, to maximize benefits accounting for costs over time without over-building transmission facilities, transmission providers must consider not only the risk that changing conditions might produce fewer benefits than originally anticipated, but also that they might produce *more* benefits than originally anticipated. Finally, as discussed below in the Reevaluation section, we require transmission providers to reevaluate certain selected Long-Term Regional Transmission Facilities to determine whether they continue to meet the transmission providers' selection criteria.

968. While we acknowledge commenters' wide support for least-regrets and weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities in Long-Term Regional Transmission Planning, we decline to require

[2119] *See, e.g.,* Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at P 242); Vistra Initial Comments at 17–18; WATT Coalition Initial Comments at 9.

[2121] Where transmission providers employ a portfolio approach to evaluating and selecting Long-Term Regional Transmission Facilities, we require only that they include in such a determination the measured benefits for the portfolio of Long-Term Regional Transmission Facilities on an aggregate basis.

[2122] *See, e.g.,* GridLab Initial Comments at 19; TAPS Initial Comments at 16–17.

transmission providers to use either approach. However, we clarify that transmission providers may not adopt an approach under which they would not select a Long-Term Regional Transmission Facility unless it meets their selection criteria in every Long-Term Scenario and sensitivity. We are concerned that such an approach could impose a threshold for selection that is so onerous it limits selection of most or all Long-Term Regional Transmission Facilities, and, as such, is inconsistent with the requirement that selection criteria seek to maximize benefits accounting for costs over time without over-building transmission facilities. We find that such an approach would not ensure that transmission providers have the opportunity to select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address Long-Term Transmission Needs, an opportunity that we find, as described in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section above, is necessary to ensure just and reasonable Commission-jurisdictional rates.

969. Again, we emphasize that this final order does not require that transmission providers select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities). Rather, this final order simply requires transmission providers to adopt an evaluation process and selection criteria that meet the minimum requirements set forth in this final order, including that they aim to maximize benefits accounting for costs over time without over-building transmission facilities. In response to NYISO,[2123] however, we decline to clarify the definition of ''over-building,'' because doing so would limit transmission providers' flexibility to assess what constitutes over-building in their transmission planning region. Transmission planning regions have a wide variety of market structures, and numerous factors drive transmission needs, which may require evaluation processes and selection criteria that maximize benefits accounting for costs or guard against over-building in different ways. We expect that evaluation processes and selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities will include a variety of features, based on their regional circumstances, that combine to ensure that transmission providers give careful, informed consideration to Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. We also note that, in response to CTC Global's concerns about the selection criteria being limited to considering regional transmission facilities with the least capital costs,[2124] we clarify that both estimated benefits and costs must be disclosed when evaluating a Long-Term Regional Transmission Facility for selection and that transmission providers must adopt selection criteria that seek to maximize benefits accounting for costs over time without over-building transmission facilities.

970. In response to Maine Public Advocate,[2125] we decline to require transmission providers to select non-transmission alternatives where such non-transmission alternatives meet a Long-Term Transmission Need at a lower cost than an alternative Long-Term Regional Transmission Facility. The Commission did not propose to require transmission providers to consider non-transmission alternatives for potential selection in the NOPR, and we are not persuaded to do so in this final order. We note, however, that transmission providers already are required to consider non-transmission alternatives on a comparable basis in regional transmission planning.[2126]

971. Finally, in response to TAPS,[2127] we decline to require transmission providers to develop affordability metrics to provide along with other information about a particular Long-Term Regional Transmission Facility. The Commission did not propose such a requirement in the NOPR, and we are not persuaded to adopt a requirement for such metrics in this final order.

4. Role of Relevant State Entities

a. NOPR Proposal

972. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a process to coordinate with the Relevant State Entities in developing selection criteria.[2128] Regarding this requirement, the Commission proposed to require transmission providers to demonstrate on compliance that they consulted with and sought support from the Relevant State Entities in their transmission planning region's footprint to develop their proposed selection criteria.[2129]

b. Comments

i. Support/Oppose

973. Many commenters support the Commission's proposal to require transmission providers to consult with and seek support from Relevant State Entities[2130] and include in their OATTs a process to coordinate with the Relevant State Entities[2131] in developing selection criteria. For example, ELCON argues that coordination with Relevant State Entities in identifying selection criteria is critical because it will promote cooperation and could result in more efficient state siting and permitting processes.[2132] Pennsylvania Commission asserts that requiring consultation will provide states the opportunity to influence regional transmission planning and cost allocation, thereby promoting the public interest and reducing conflicts and disputes on these matters.[2133]

974. ISO–NE supports the proposal to provide states with a greater role in the selection of transmission facilities.[2134] Further, ISO–NE argues that, in the context of policy-based planning, states should be responsible for determining whether to select transmission facilities, with ISO–NE playing a supporting, technical role.[2135] While NESCOE supports the proposal that transmission providers must consult with and seek support from Relevant State Entities within their transmission planning region's footprint to develop selection criteria, NESCOE requests that the Commission provide Relevant State Entities an expanded role in the selection of transmission projects where the project is identified as needed in response to state laws or policy goals and require transmission providers to include such a role in their OATTs.[2136]

[2123] NYISO Initial Comments at 43.

[2124] CTC Global Initial Comments at 9.

[2125] Maine Public Advocate Initial Comments at 1–2.

[2126] Order No. 1000, 136 FERC ¶ 61,051 at P 148.

[2127] TAPS Initial Comments at 16–17, 19–20 (citations omitted).

[2128] NOPR, 179 FERC ¶ 61,028 at P 241.

[2129] *Id.* P 246.

[2130] *See* ACEG Initial Comments at 59–60; Ameren Initial Comments at 20; American Municipal Power Initial Comments at 12; California Commission Initial Comments at 37; ELCON Initial Comments at 17; Nebraska Commission Initial Comments at 8–9; North Carolina Commission and Staff Initial Comments at 4–5; Pennsylvania Commission Initial Comments at 10; PJM States Initial Comments at 3.

[2131] *See* NARUC Initial Comments at 44; NESCOE Initial Comments at 9–10, 46; Pacific Northwest State Agencies Initial Comments at 19; PJM States Initial Comments at 3.

[2132] ELCON Initial Comments at 17.

[2133] Pennsylvania Commission Initial Comments at 10.

[2134] ISO–NE Initial Comments at 35.

[2135] *Id.* NESCOE supports ISO–NE's position. NESCOE Reply Comments at 5 & n.16.

[2136] NESCOE Initial Comments at 9–10, 48–49.

975. PJM states that it also supports providing additional opportunity for involvement by states and stakeholders in Long-Term Regional Transmission Planning; however, in response to ISO–NE, PJM urges the Commission to make clear that transmission providers retain authority to select transmission facilities and argues that such role is more than a ''technical supporting role.'' [2137] PJM States contend that an upfront and transparent process, with substantive state involvement, will ensure that selection criteria are thoroughly discussed by stakeholders and are consistent with the rest of Long-Term Regional Transmission Planning.[2138]

976. New York Commission and NYSERDA state that the Commission should allow Relevant State Entities to be part of the decision-making process regarding the appropriate timeframe for selecting a transmission facility.[2139]

977. California Commission urges the Commission to require that transmission providers indicate in their compliance filings whether the selection criteria they propose are supported by the Relevant State Entities and, if not, to explain any points of disagreement.[2140] PJM States argue that the Commission should, without dictating any substantive outcomes, ''recognize the primacy of the role for retail regulators'' in the final order.[2141] By contrast, ACEG cautions that transmission providers must balance all states' interests when developing selection criteria instead of maximizing one state's interest over another's.[2142] NYISO states that each transmission planning region should have flexibility to determine how it will consult with and seek support from Relevant State Entities regarding selection criteria.[2143]

978. To ensure that consultation is successful, NARUC recommends that the Commission require transmission providers to take two steps: (1) communicate with the Relevant State Entities promptly following issuance of a final order in a manner that is reasonably calculated to be received by the Relevant State Entities; and (2) establish a forum for negotiation that enables full and robust participation by both transmission providers and Relevant State Entities during the period allotted for making compliance filings.[2144]

979. Some commenters oppose the Commission's NOPR proposal.[2145] Dominion argues that mandating involvement by Relevant State Entities would unnecessarily burden transmission providers.[2146] Louisiana Commission argues that the proposal would represent ''superficial state involvement'' and serve as ''window dressing'' for the erosion of state authority due to Long-Term Regional Transmission Planning. Louisiana Commission argues that collective oversight by the states within an RTO/ISO is not equivalent to state oversight of its own retail electric service companies, particularly in circumstances where states are subject to the decisions of the majority.[2147]

980. APPA opposes any requirement for transmission providers to consult with, and/or seek the support of, Relevant State Entities in identifying selection criteria.[2148] APPA contends that Relevant State Entities should be considered in the same manner as other stakeholders under the requirements of Order Nos. 890 and 1000.[2149] DC and MD Offices of People's Counsel disagree with APPA, arguing that the Commission should afford Relevant State Entities an expansive role in the selection of transmission facilities in Long-Term Regional Transmission Planning.[2150] DC and MD Offices of People's Counsel contend that Relevant State Entities can reach agreement quickly and have access to the best available data used for baseline planning and scenario analysis of transmission facilities.[2151]

981. MISO takes no position but argues that its existing processes already entail extensive stakeholder engagement, including consulting with state regulatory commissions individually and through OMS, to determine the selection criteria that should be used to maximize long-term transmission value and to ensure an adequate, reliable, and resilient transmission system.[2152]

ii. Obtaining/Not Obtaining Consent

982. Several commenters discuss whether transmission providers need only consult with and seek support from Relevant State Entities in the development of selection criteria, or whether they also must obtain their consent.[2153] For example, Indicated PJM TOs support the NOPR proposal but argue that the Commission should not require transmission providers to obtain the agreement of Relevant State Entities in determining selection criteria.[2154] AEP agrees and argues that state input should be only one factor and that engineering considerations should drive the establishment of selection criteria. AEP also expresses skepticism that requiring transmission providers to consult with Relevant State Entities will increase the chances that states will site the transmission facilities that transmission providers select, because transmission line siting processes will occur years after the establishment of selection criteria, will likely be performed by different personnel, and will address considerations separate from those in establishing selection criteria.[2155]

983. Southeast PIOs argue that, while they do not oppose factoring state and consumer support into the selection of transmission facilities, the Commission should not require transmission providers to obtain the approval of Relevant State Entities prior to selection of transmission facilities, because doing so would risk indefinitely delaying Long-Term Regional Transmission Planning.[2156]

984. PJM argues that it should be able to develop selection criteria in the event that Relevant State Entities do not agree on the establishment of selection criteria. PJM recommends that the Commission clarify that any requirement to demonstrate that transmission providers have consulted with and sought support from Relevant State Entities could be satisfied even if the transmission provider is unable to secure the agreement of Relevant State Entities.[2157]

985. By contrast, NARUC opposes a process in which transmission providers consult with and seek support from Relevant State Entities but are empowered to override or ignore selection criteria proposed and

[2137] PJM Reply Comments at 35–36 (citing ISO–NE Initial Comments at 16).

[2138] PJM States Reply Comments at 8.

[2139] New York Commission and NYSERDA Initial Comments at 12.

[2140] California Commission Initial Comments at 37–38.

[2141] PJM States Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

[2142] ACEG Initial Comments at 59–60.

[2143] NYISO Initial Comments at 44.

[2144] NARUC Initial Comments at 44.

[2145] *See, e.g.,* Clean Energy Associations Initial Comments at 22–23 (arguing that, while state involvement should play a role, the Commission should set forth *pro forma* selection criteria).

[2146] Dominion Initial Comments at 37–38.

[2147] Louisiana Commission Initial Comments at 27.

[2148] APPA Initial Comments at 34.

[2149] *Id.*

[2150] DC and MD Offices of People's Counsel Reply Comments at 9 (citing APPA Initial Comments at 35).

[2151] *Id.*

[2152] MISO Initial Comments at 55.

[2153] *See, e.g.,* Acadia Center and CLF Initial Comments at 27–28 (arguing that states should have veto authority over transmission providers' selection criteria in certain circumstances).

[2154] Indicated PJM TOs Initial Comments at 18 (citing NOPR 179, FERC ¶ 61,028 at PP 244, 246).

[2155] AEP Initial Comments at 29–30.

[2156] Southeast PIOs Reply Comments at 27.

[2157] PJM Initial Comments at 104.

supported by Relevant State Entities. NARUC seeks clarification as to what recourse will be available to Relevant State Entities in the event that there is not agreement on selection criteria.[2158] Nebraska Commission argues that the Commission should require transmission providers to demonstrate to the greatest extent possible that they gained the support of Relevant State Entities, because otherwise the process of consulting with and seeking support from Relevant State Entities could become a mere exercise.[2159]

986. Mississippi Commission suggests that the Commission require transmission providers to obtain the agreement of Relevant State Entities on selection criteria for Long-Term Regional Transmission Planning.[2160] Southern goes further, arguing that the Commission should allow Relevant State Entities to use the State Agreement Process not only to allocate the costs of Long-Term Regional Transmission Facilities, but also to select such transmission facilities in the first instance. Southern contends that, if the Commission does not allow states to select transmission facilities, the Commission will unlawfully intrude into state jurisdiction over resource planning.[2161]

987. Acadia Center and CLF assert that states should have the authority to propose selection criteria, arguing that this will ensure that transmission providers do not refuse to consider states' interests and goals regarding transmission needs. Acadia Center and CLF further contend that states should have veto authority over transmission providers' selection criteria in certain scenarios, such as ISO–NE, where a majority of states in a transmission planning region have decarbonization goals but the ISO/RTO continues to apply business-as-usual selection criteria that prioritize reliability and economic considerations.[2162]

988. AEE argues that the final order should clearly provide an opportunity for states to suggest selection criteria and inputs for analyzing transmission projects, noting that such a process may need to be continually developed following issuance of a final order.[2163]

[2158] NARUC Initial Comments at 45.

[2159] Nebraska Commission Initial Comments at 8–9.

[2160] Mississippi Commission Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 11)).

[2161] Southern Initial Comments at 6–10 & n.12 (citations omitted).

[2162] Acadia Center and CLF Initial Comments at 27–28.

[2163] AEE Initial Comments at 30–32 (citations omitted).

iii. Consultation With Other Entities

989. A number of commenters argue that transmission providers should consult with and seek support from other entities in addition to Relevant State Entities. Large Public Power does not object to the NOPR proposal but argues that it is essential that municipal utilities also be included as participants in the consultative process.[2164] American Municipal Power urges the Commission to recognize that publicly-owned utilities play a role analogous to state commissions, in that they are publicly accountable, operate through open and transparent procedures, and adopt policies reflecting the consensus of communities that own and support them. American Municipal Power argues that FPA section 217(b)(4) requires the Commission to revise the NOPR proposal such that load-serving entities, including publicly-owned utilities, are on a par with Relevant State Entities.[2165] NRECA agrees, arguing that Relevant State Entities may not have regulatory authority over electric cooperatives, and therefore the Commission must modify its proposal to include consultation with load-serving entities to conform with FPA section 217(b)(4) and Order No. 1000's transmission planning principles.[2166]

990. Relatedly, NARUC argues that nothing in the final order should inhibit states from permitting the participation of certain quasi-public/private state and Federal entities or other state entities in addition to Relevant State Entities.[2167] NEPOOL states that the selection of any transmission facilities should be made with substantial input from both market participant stakeholders and the transmission planning region's states.[2168]

iv. Practical Implementation Issues

991. Several commenters discuss practical issues with the requirement that transmission providers consult with and seek the support of Relevant State Entities in developing selection criteria. For example, PPL generally supports the Commission's proposal but contends that some states may find it difficult to fulfill the role described in the NOPR. PPL therefore argues that the Commission should allow transmission providers flexibility in developing consultative processes.[2169] AEP argues that some states will be unable to participate effectively given a lack of resources or statutory limitations, such that the consultative process may result in selection criteria "that unfairly or unreasonably emphasize certain values." [2170] NESCOE states that the Commission should provide flexibility as to how states elect to engage in the transmission planning process, noting that a state official's role in siting electric infrastructure may make it preferable for a different state official to provide that state's view on certain aspects of Long-Term Regional Transmission Planning, such as transmission project selection.[2171]

[2164] Large Public Power Initial Comments at 30.

[2165] American Municipal Power Initial Comments at 12–13.

[2166] NRECA Initial Comments at 50.

[2167] NARUC Initial Comments at 29–30 (citation omitted).

[2168] NEPOOL Initial Comments at 8.

[2169] PPL Initial Comments at 18–19.

992. NEPOOL requests that the Commission articulate principles for who should make selection decisions when a Long-Term Regional Transmission Facility may address transmission needs driven by reliability, economics, and public policy.[2172]

993. Michigan State Entities argue that the success of the Commission's proposed reforms depends on transmission providers meaningfully engaging with stakeholders, which requires that stakeholders have the time and capability to participate in a stakeholder review process. Michigan State Entities further assert that stakeholders representing diffuse and broad interests (*e.g.,* residential ratepayers), as opposed to concentrated interests, tend to have fewer resources with which to fund participation in these processes, noting that many states have created consumer advocacy agencies to correct this imbalance. Michigan State Entities assert that the Commission should require that transmission providers include RTO/ISO-level, publicly funded consumer advocates in the stakeholder processes that are empowered to participate in approving selection criteria.[2173]

c. Commission Determination

994. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consult with and seek support from Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional Transmission Facilities for selection. Specifically, we require transmission providers to demonstrate on compliance that they made good

[2170] AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290).

[2171] NESCOE Initial Comments at 9 n.16.

[2172] NEPOOL Initial Comments at 8.

[2173] Michigan State Entities Initial Comments at 4–5.

faith efforts to consult with and seek support from Relevant State Entities in their transmission planning region's footprint when developing the evaluation process and selection criteria that they propose to include in their OATTs.[2174]

995. We decline to adopt the NOPR proposal to require transmission providers to include in their OATTs a process for coordinating with Relevant State Entities. We believe that the requirement adopted in this final order will simplify compliance efforts without sacrificing the benefits of consulting with and seeking the support of Relevant State Entities. We disagree with Dominion that requiring transmission providers to consult with and seek support from Relevant State Entities will prove burdensome, and we believe that our decision not to require transmission providers to include a process for such consultation in their OATTs will further reduce any administrative burden of this requirement.[2175]

996. We clarify that we require transmission providers to seek support from Relevant State Entities, but do not require transmission providers to obtain their support, before proposing an evaluation process and selection criteria on compliance.[2176] In response to Acadia Center and CLF, we note that Relevant State Entities may propose selection criteria to transmission providers, but ultimately, it is transmission providers who must propose on compliance an evaluation process and selection criteria that comply with the requirements of this final order. We further note that providing states with veto authority over transmission providers' proposed selection criteria would be akin to requiring transmission providers to obtain the support of Relevant State Entities, and therefore we do not adopt Acadia Center and CLF's recommendation.[2177] While we believe that Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation process and selection criteria, we reiterate that transmission planning is the tariff obligation of each transmission provider and transmission providers retain ultimate responsibility for regional transmission planning, including Long-Term Regional Transmission Planning, as well as complying with the obligations of this final order.[2178] Moreover, we acknowledge that achieving consensus may not be possible in every instance.

997. We disagree with NARUC that, in the absence of a requirement that transmission providers obtain the support of Relevant State Entities, transmission providers will be empowered to ignore the input of Relevant State Entities. In this final order, we require transmission providers to make good faith efforts to consult with and seek the support of Relevant State Entities. We do not agree that the failure to obtain the support of Relevant State Entities is necessarily evidence that transmission providers did not exercise good faith efforts to seek their support.

998. For similar reasons, we also disagree with Louisiana Commission when it argues that requiring transmission providers to simply consult with and seek support from Relevant State Entities will amount to only superficial state involvement in the development of an evaluation process and selection criteria.[2179] In response to Louisiana Commission's additional contention that collective oversight of regional transmission planning processes by the transmission planning region's states is not equivalent to state oversight of its own retail electric service companies, we reiterate that this final order requires transmission providers to engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs in order to ensure *Commission-jurisdictional* rates are just and reasonable. As discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, the final order neither aims at nor conflicts with state authority over retail rates.

999. We do not believe that it is necessary to adopt California Commission's proposal to require transmission providers to indicate in their compliance filings whether Relevant State Entities support the proposal or explain any points of disagreement that they may have with Relevant State Entities. Relevant State Entities may intervene in compliance filing proceedings and provide this information for the Commission's consideration as it determines whether transmission providers have met the requirements that we adopt in this final order. Nor do we adopt NARUC's request that we impose specific requirements dictating how transmission providers should consult with and seek the support of Relevant State Entities beyond the requirement that they demonstrate good faith efforts to do so. We believe that it is appropriate to provide transmission providers with flexibility in how to consult with and seek support of Relevant State Entities based on the specific needs and makeup of their transmission planning region. Further, we acknowledge, as argued by some commenters,[2180] that practical or legal limitations may limit the extent to which some Relevant State Entities may participate in such processes, reinforcing the need for flexibility.

1000. We clarify that nothing in this final order diminishes the role of stakeholders that are not Relevant State Entities, nor absolves transmission providers of any existing obligations that they may have to provide opportunities for stakeholder input.[2181] That said, we decline to require transmission providers to consult with or seek support from entities in addition to Relevant State Entities, including load-serving entities.[2182] This final order recognizes that Relevant State Entities play a unique role in representing the interests of states, which retain a variety of authorities, including those under FPA section 201, that are integral to the success of Long-Term Regional Transmission Planning.

1001. Further, we disagree with American Municipal Power that FPA section 217(b)(4) requires that this final order treat load-serving entities on par with Relevant State Entities. Through the requirements of this final order, we seek to ensure that adequate

[2174] In response to New York Commission and NYSERDA, we note that such consultation may include discussion of the appropriate timeframe for selecting a Long-Term Regional Transmission Facility. New York Commission and NYSERDA Initial Comments at 12.

[2175] *See* Dominion Initial Comments at 37–38.

[2176] *See, e.g.,* PJM Initial Comments at 104 (requesting clarification that transmission providers are permitted to submit an evaluation process and selection criteria on compliance in the absence of obtaining the support of Relevant State Entities).

[2177] *See* Acadia Center and CLF Initial Comments at 27–28.

[2178] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 153 (''[T]he ultimate responsibility for transmission planning remains with public utility transmission providers.'' (citing Order No. 890, 118 FERC ¶ 61,119 at P 454)).

[2179] Louisiana Commission Initial Comments at 27.

[2180] *See* AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290); NESCOE Initial Comments at 9 n.16; PPL Initial Comments at 18–19.

[2181] In response to NARUC and NEPOOL, *see* NARUC Initial Comments at 29–30; NEPOOL Initial Comments at 9, we reiterate that this may include other state entities in addition to Relevant State Entities, such as Federal entities, market participants, and other stakeholders.

[2182] *See, e.g.,* American Municipal Power Initial Comments at 12–13; Large Public Power Initial Comments at 30.

transmission capacity is built to allow load-serving entities to meet their service obligations and facilitate the planning of a reliable grid, consistent with FPA section 217(b)(4). Nothing in our determination to require transmission providers to consult with and seek support from Relevant State Entities (but not load-serving entities) changes that aim or undercuts the ability of Long-Term Regional Transmission Planning to achieve it. We continue to find that other requirements in the final order, including the requirement to incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities in the development of Long-Term Scenarios, ensure load-serving entities' reasonable needs for transmission capacity to meet their service obligations are incorporated into Long-Term Regional Transmission Planning.

1002. Finally, in response to commenters,[2183] we clarify that transmission providers, not Relevant State Entities, must determine whether or not to select Long-Term Transmission Facilities to meet Long-Term Transmission Needs. Under the FPA, the Commission has jurisdiction over transmission providers, and those entities, not Relevant State Entities, are subject to the requirements of this final order. As discussed above in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section, we require herein that transmission providers designate a point in the evaluation process at which they will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).

5. Voluntary Funding Opportunities

a. NOPR Proposal

1003. In the NOPR, the Commission sought comment on whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility to enable such facility to meet transmission providers' selection criteria (*e.g.,* any benefit-cost threshold), and if so, what mechanism would be appropriate to document such voluntary funding agreements, how transmission providers would be assured that commitments to provide funding would be sufficiently binding, and what the most appropriate point would be in the process for such voluntary commitments.[2184] The Commission also sought comment on whether such a voluntary funding opportunity should be extended to other entities, such as interconnection customers.[2185]

b. Comments

1004. Of commenters that address the question posed in the NOPR regarding whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility, nearly all argue that the Commission should allow such an opportunity.[2186] ISO–NE argues that the Commission should provide flexibility to transmission providers to determine the specific means for documenting the state's agreement to provide such funding.[2187] APPA argues that the Commission should require the filing under FPA section 205 of agreements to fund the cost of, or a portion of the cost of, a transmission facility so that affected parties have an opportunity to comment.[2188]

1005. Grid United argues that, while it supports *ex ante* cost allocation methods, the Commission also should continue to permit alternative cost recovery arrangements, including participant funding agreements and voluntary agreements entered into by generation developers and Relevant State Entities.[2189] Duke asserts that the Commission should avoid prescriptive rules that discourage or undervalue voluntary funding from transmission providers, states, Relevant State Entities, or interconnection customers.[2190] Xcel argues that the Commission should state in a final order that neither the FPA nor the Commission's rules and regulations forbid voluntary arrangements for planning and paying for transmission facilities.[2191]

1006. NARUC argues that the final order should not inhibit the flexibility of Relevant State Entities in developing approaches to such voluntary funding commitments.[2192] NARUC argues that the final order should be as flexible as possible in providing voluntary funding opportunities to account for the variety of state laws enabling such authority and to allow for the possibility of sharing the costs of such transmission facilities between load and generator developers.[2193]

1007. Louisiana Commission supports the NOPR proposal and argues that voluntary agreement is the only fair, reasonable, and just way to allocate the costs of transmission facilities selected in Long-Term Regional Transmission Planning.[2194] Ameren believes that Relevant State Entities should have the opportunity to fund a portion of the cost of a transmission facility that otherwise would not meet the OATT selection criteria but requests that the Commission clarify that this decision "is referring to cost allocation." [2195] Ameren argues that without this clarification, Relevant State Entities could fund part of the transmission facility while imposing on a transmission owner the obligation to operate and maintain that facility and assure regulatory compliance without adequate compensation, in violation of the D.C. Circuit's determination in *Ameren Services Co.* v. *FERC* that transmission owners "should not be forced to operate as a non-profit." [2196]

[2183] *See, e.g.,* ISO–NE Initial Comments at 35 (arguing that states should be responsible for determining whether to select transmission facilities and that transmission providers should play a supportive, technical role); NEPOOL Initial Comments at 8 (requesting that the Commission articulate principles for who should select multi-value transmission facilities); NESCOE Initial Comments at 9,48–49 (requesting that the Commission require transmission providers to include a role in their OATTs for Relevant State Entities in the selection of Long-Term Regional Transmission Facilities); PJM Reply Comments at 36 (requesting that the Commission clarify that transmission providers retain the authority to select transmission facilities).

[2184] NOPR, 179 FERC ¶ 61,028 at P 252. The Commission stated that, for Long-Term Regional Transmission Facilities, such an opportunity for the Relevant State Entities could enable them to assign a value to achieving their particular policy goals while ensuring that their customers bear the corresponding costs. *Id.* P 252 n.399.

[2185] *Id.*

[2186] *See* Ameren Initial Comments at 21; APPA Initial Comments at 34–35; Clean Energy Associations Initial Comments at 23; Duke Initial Comments at 28–29; Grid United Initial Comments at 6; Idaho Commission Initial Comments at 5; ISO–NE Initial Comments at 36; Louisiana Commission Initial Comments at 29; NARUC Initial Comments at 31–32 (citing *MISO–SPP Joint Targeted Interconnection Queue Study (JTIQ),* MISO, *https://www.misoenergy.org/engage/committees/miso-spp-joint-targeted-interconnection-queue-study/*); New Jersey Commission Initial Comments at 25; PPL Initial Comments at 19; SDG&E Initial Comments at 4; WATT Coalition Initial Comments at 11; Xcel Initial Comments at 14 (stating that neither the FPA nor the Commission's rules and regulations categorically preclude voluntary agreement to plan and pay for new transmission facilities (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 561, 724; *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at P 3)).

[2187] ISO–NE Initial Comments at 36.

[2188] APPA Initial Comments at 34–35 (citing *PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024 (2022)).

[2189] Grid United Initial Comments at 6.

[2190] Duke Initial Comments at 28–29.

[2191] Xcel Initial Comments at 14.

[2192] NARUC Initial Comments at 31–32; *accord* Idaho Commission Initial Comments at 5.

[2193] NARUC Initial Comments at 32.

[2194] Louisiana Commission Initial Comments at 29.

[2195] Ameren Initial Comments at 21–22 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

[2196] *Id.* (citing *Ameren Servs. Co.* v. *FERC,* 880 F.3d 571 (D.C. Cir. 2018)).

1008. Clean Energy Associations suggest two mechanisms to provide opportunities for states and interconnection customers to ensure that necessary transmission facilities are built. First, Clean Energy Associations would provide a ''Transmission Alternative Right,'' through which states or interconnection customers could pay the difference between evaluated benefits and the level of benefits necessary to meet the applicable benefits threshold. Second, Clean Energy Associations would provide a ''Transmission Expansion Right,'' which would allow states or interconnection customers to provide funding to expand transmission facilities beyond those identified in Long-Term Regional Transmission Planning. With respect to this second right, Clean Energy Associations contend that the funding parties should receive time-limited priority usage of additional transmission expansion that they fund and retain incremental capacity attributes associated with the expanded capability.[2197] Clean Energy Associations also suggest that the portion of the expanded Long-Term Regional Transmission Facility originally identified in the regional transmission plan would receive the applicable regional cost allocation.[2198]

1009. New Jersey Commission argues that allowing Relevant State Entities the opportunity to fund the cost of or part of the cost of transmission facilities would provide a way to value a transmission facility's public policy benefits and a mechanism for co-optimizing reliability and economic benefits while meeting public policy needs. However, New Jersey Commission states that, while the proposed 20-year transmission planning horizon should ensure that transmission providers identify opportunities for multi-driver transmission projects in sufficient time for states to provide funding, the Commission should mandate that transmission providers reach out to Relevant State Entities to inform them of such opportunities on a timely basis.[2199]

1010. SPP takes no position on the voluntary funding issue but states that its Regional State Committee developed a cost allocation framework that includes the option for entities to sponsor specific transmission projects, assuming cost responsibility without imposing burdens on others through the general rate structure. SPP states that this mechanism could be used by a state or states to fund projects that SPP otherwise would not select.[2200]

1011. While PPL supports the ability of states to fund the cost of, or a portion of the costs of, transmission facilities that otherwise would not meet selection criteria, PPL argues that the final order should not require transmission providers to facilitate such an opportunity with states.[2201] APS contends that it is not appropriate for a Relevant State Entity to volunteer its ratepayers to fund, and APS to build, a transmission facility. APS explains that Arizona is a diverse state with several non-jurisdictional entities; as such, APS contends that the state would not have the authority to volunteer all the state's ratepayers to fund the transmission facility, which ultimately may burden transmission providers with additional costs and responsibilities.[2202]

c. Commission Determination

1012. We modify the NOPR proposal and require transmission providers in each transmission planning region to include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria. We provide transmission providers with the flexibility to propose certain features of such a voluntary funding process in their compliance filings.[2203] However, this voluntary funding process must be transparent and not unduly discriminatory or preferential and provide for the four components discussed below. Further, as with other aspects of the evaluation process and selection criteria, transmission providers must consult with and seek support from Relevant State Entities when developing a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that they propose to include in their OATTs.

1013. In setting forth the requirement that transmission providers include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria, we direct transmission providers to propose OATT provisions on compliance that describe: (1) the process by which the transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that Relevant State Entities and interconnection customers receive timely notice of such opportunities and provide a meaningful opportunity for Relevant State Entities and interconnection customers; (2) the period during which Relevant State Entities and interconnection customers may exercise the option to provide voluntary funding; (3) the method that transmission providers will use to determine the amount of voluntary funding required to ensure that the Long-Term Regional Transmission Facility meets the transmission providers' selection criteria; and (4) the mechanism through which transmission providers and Relevant State Entities or interconnection customers will memorialize any voluntary funding agreement, *e.g.,* a *pro forma* agreement in the OATT. We clarify that, for any portion of the costs of a selected Long-Term Regional Transmission Facility that is *not* voluntarily funded by a Relevant State Entity (or Entities) or interconnection customers, those remaining costs must be allocated according to the applicable Long-Term Regional Transmission Cost Allocation Method (or cost allocation method resulting from a State Agreement Process, if such a process is adopted by the transmission providers in the associated transmission planning region).

1014. We believe that requiring transmission providers to include a voluntary funding process in their OATTs ultimately may increase the number of Long-Term Regional Transmission Facilities that are selected. The voluntary funding processes that we are requiring transmission providers to include in their OATTs will allow Relevant State Entities and interconnection customers to voluntarily fund the cost of, or a portion of the cost of, a Long-Term

[2197] Clean Energy Associations Initial Comments at 23–24 (citing Clean Energy Associations ANOPR Initial Comments at 76). Clean Energy Associations assert this would be consistent with Order No. 807. *Id.* (citing Clean Energy Associations ANOPR Initial Comments at 76–78; *Open Access & Priority Rights on Interconnection Customer's Interconnection Facilities,* Order No. 807, 150 FERC ¶ 61,211, at P 109, *order on reh'g,* Order No. 807–A, 153 FERC ¶ 61,047 (2015)).

[2198] *See id.*

[2199] New Jersey Commission Initial Comments at 28.

[2200] SPP Initial Comments at 22 (citing SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), § 7.2).

[2201] PPL Initial Comments at 19.

[2202] APS Initial Comments at 10.

[2203] *See* ISO–NE Initial Comments at 36; NARUC Initial Comments at 31–32 (requesting flexibility to design voluntary funding processes).

Regional Transmission Facility, with any remaining costs allocated to beneficiaries in a manner that is at least roughly commensurate with the estimated benefits that they will receive. As such, a voluntary funding process will allow the development of Long-Term Regional Transmission Facilities that Relevant State Entities or interconnection customers believe are beneficial but that might not otherwise be selected.[2204] We also believe that such a voluntary funding process could help transmission providers to avoid, manage, or resolve otherwise difficult disputes among stakeholders in their transmission planning regions, such as those arising from situations in which Relevant State Entities or interconnection customers value the development of certain Long-Term Regional Transmission Facilities differently.

1015. We acknowledge, consistent with APS's comments, that in certain states Relevant State Entities may not have the necessary authority to require all of that state's ratepayers to provide the funding needed to take advantage of voluntary funding opportunities.[2205] We do note, however, nothing in this final order is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to the ability of any Relevant State Entity to voluntarily fund any costs of a Long-Term Regional Transmission Facility. Whether and to what extent a Relevant State Entity chooses to take advantage of an opportunity to voluntarily fund the costs of a Long-Term Regional Transmission Facility is dependent on whether that entity has the requisite authority to do so.

1016. In response to Ameren,[2206] we decline to determine at this point what effect *Ameren Services Co.* v. *FERC* may have on voluntary funding arrangements or the allocation of the costs of a transmission facility net of that voluntary funding, which may depend on how transmission providers propose to allow for voluntary funding opportunities.

1017. We decline Clean Energy Associations' request that we require transmission providers to allow voluntary funding opportunities to expand a Long-Term Regional Transmission Facility beyond what was identified through Long-Term Regional Transmission Planning (*e.g.,* voluntarily funding the construction of a 500 kV transmission line where a 345 kV transmission line was identified through Long-Term Regional Transmission Planning).[2207] While we recognize that there may be interest in providing additional opportunities for voluntary funding, we find that there is insufficient record evidence to support imposing this modification to the voluntary funding opportunity we require in this final order. We note, however, that nothing in this final order prohibits this type of voluntary funding approach and transmission providers may either seek to demonstrate that a proposal including such an approach is consistent with or superior to what is required by this order, or else submit a filing under FPA section 205 to propose the inclusion in their OATTs of voluntary funding opportunities that go beyond those required in this final order.

1018. Finally, in response to APPA,[2208] we decline to impose any specific requirement for transmission providers to file agreements that memorialize voluntary funding arrangements under FPA section 205. The Commission will evaluate on compliance the mechanism that transmission providers propose for memorializing voluntary funding agreements between transmission providers and Relevant State Entities or interconnection customers, as applicable.

6. No Selection Requirement

a. NOPR Proposal

1019. The Commission did not propose in the NOPR to require that transmission providers select transmission facilities, even in the event that a transmission facility meets the selection criteria established by the transmission providers.[2209]

b. Comments

1020. Many commenters express opposition to any potential requirement under which the Commission would require transmission providers to select Long-Term Regional Transmission Facilities.[2210] For example, ISO–NE states that the final order should be clear that transmission providers are not required to select any identified Long-Term Regional Transmission Facilities for inclusion in system plans or cost allocation purposes, and NESCOE agrees.[2211] Ameren contends that a mandate to select any transmission facility may result in over-building the transmission system.[2212] Xcel makes a similar point, arguing that it would result in a loss of confidence in the transmission planning process. Furthermore, Xcel argues, transmission planning is subjective and removing all discretion from transmission planners would result in bad outcomes.[2213]

1021. SERTP Sponsors urge the Commission to make clear that there is no requirement for transmission providers to select Long-Term Regional Transmission Facilities based on long-term studies without specific express support and agreement of the relevant regulatory authorities and policy makers.[2214] NRECA asserts that transmission planning using a 20-year transmission planning horizon is an exercise fraught with uncertainty, and requests that the Commission clarify that it is not mandating that transmission providers select Long-Term Regional Transmission Facilities 20 years in advance.[2215] NRECA states that other commenters also expressed concerns about risks to consumers associated with selecting transmission projects in the regional transmission plan for purposes of cost allocation 20 years before they may be needed.[2216]

[2204] *See, e.g.,* New Jersey Commission Initial Comments at 25–26 (arguing that voluntary funding would provide a way to value a transmission facility's public policy benefits and a mechanism for co-optimizing reliability and economic benefits while meeting public policy needs).

[2205] APS Initial Comments at 10.

[2206] Ameren Initial Comments at 21–22.

[2207] Clean Energy Associations Initial Comments at 23–24 (citations omitted).

[2208] APPA Initial Comments at 34–35 (citing *PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024).

[2209] *See* NOPR, 179 FERC ¶ 61,028 at P 9 (noting that the proposed reforms related to regional transmission planning and cost allocation requirements, like those of Order Nos. 890 and 1000, are focused on the transmission planning process, and not on any substantive outcomes that may result from this process); *see also id.* P 241 (requiring transmission providers to propose selection criteria to identify and evaluate transmission facilities for *potential selection*).

[2210] *See, e.g.,* California Water Initial Comments at 14–15; Dominion Initial Comments at 18; Dominion Reply Comments at 8 (citing NARUC Initial Comments at 5–6, 39); ISO–NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Initial Comments at 46–47; NRECA Initial Comments at 48; NRECA Reply Comments at 4–8 (citations omitted); NYISO Initial Comments at 44 (citing *N.Y. Indep. Sys. Operator, Inc.,* 148 FERC ¶ 61,044, at P 125 (2014)); TANC Initial Comments at 10.

[2211] ISO–NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO–NE Initial Comments at 35–36).

[2212] Ameren Initial Comments at 13 (citing Large Public Power Initial Comments at 10).

[2213] Xcel Initial Comments at 13–14.

[2214] SERTP Sponsors Initial Comments at 5; *see also* Alabama Commission Initial Comments at 3 (contending that Long-Term Regional Transmission Planning should not involve selection or construction obligations unless the affected state regulators support such actions).

[2215] NRECA Initial Comments at 27, 48.

[2216] NRECA Reply Comments at 4–8 (citing APPA Initial Comments at 22, 24–36; California Municipal Utilities Initial Comments at 2–3, 5–7, 15; ELCON Initial Comments at 10; Large Public Power Initial Comments at 6–8, 11–13; Nebraska Commission Initial Comments at 2; New York Commission and

1022. Dominion claims that Long-Term Regional Transmission Planning should not be a mandated development and construction plan of transmission facilities and argues that it should instead merely be a tool to help transmission providers understand where transmission needs may exist now and in the future.[2217]

1023. PJM requests that the Commission clarify that transmission providers can identify trends across multiple Long-Term Regional Transmission Planning cycles without needing to select specific transmission facilities, arguing that it should have the flexibility to open solicitations for transmission facilities as system needs arise.[2218]

1024. A few commenters favor selection mandates in at least some circumstances. For example, Eversource argues that the Commission should consider requiring transmission providers to address transmission needs that are identified in multiple Long-Term Scenarios or in the ''high-impact, low-frequency event'' scenario. Eversource contends that transmission providers otherwise risk failing to select transmission facilities that will greatly increase reliability, resiliency, and affordability.[2219]

1025. PIOs state that experience with Order No. 1000 demonstrates that some transmission providers may only do the bare minimum to comply and therefore may fail to select, allocate the costs of, or construct much needed transmission. As such, PIOs state, the Commission should require transmission providers to use good faith efforts to select recommended transmission facilities.[2220]

c. Commission Determination

1026. The Commission did not propose in the NOPR, and we will not require in this final order, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.[2221] This final order improves regional transmission planning processes by ensuring that transmission providers identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities that resolve those needs and assess the benefits thereof, and provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities. In other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.

1027. We believe that transmission providers implementing Long-Term Regional Transmission Planning and developing regional transmission plans require the flexibility to balance competing interests in the transmission planning region and to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements.

1028. We clarify that nothing in this final order prohibits transmission providers from proposing to impose upon themselves a requirement to select a Long-Term Regional Transmission Facility in certain circumstances. For example, transmission providers might propose selection criteria that would require them to select a Long-Term Regional Transmission Facility if it would meet a Long-Term Transmission Need that appears in multiple Long-Term Scenarios, or if it exceeded selection criteria by a pre-set margin.

7. Other Issues

a. Comments

1029. Clean Energy Associations argue that any transmission projects that are approved at the end of a transmission planning cycle should be included in updated models in the next transmission planning cycle, as well as in generation interconnection studies.[2222]

1030. R Street argues that the status quo selection process undermines the NOPR's objective of advancing efficient and cost-effective transmission expansion and that many transmission projects, especially reliability projects, are not subject to economic scrutiny. Therefore, R Street argues that the Commission should require that all transmission projects pass a cost-benefit analysis under the purview of an independent transmission planner and/or monitor across all Order No. 1000 transmission planning regions.[2223]

b. Commission Determination

1031. In response to Clean Energy Associations, we clarify that we are not imposing specific requirements regarding the treatment of selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles, beyond the overall requirements discussed in the Development of Long-Term Scenarios section of this final order. As we explain above, selection is only one of a number of steps in the transmission development process, and we believe that it is appropriate to provide transmission providers flexibility on how to update their planning models in a manner that most effectively addresses the specifics of their regional transmission planning processes, consistent with the requirements of this final order.

1032. Finally, we note that this final order generally does not require transmission providers to replace or otherwise make changes to existing Order No. 1000 regional reliability and economic transmission planning and cost allocation processes. As such, we decline to adopt R Street's proposal to require that all transmission projects pass a cost-benefit analysis.

8. Reevaluation

a. NOPR Proposal

1033. The Commission proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility. The Commission proposed that the existing transmission developer requirements would apply, including that the developer of the selected regional transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals necessary to develop and construct the transmission facility such that it meets the transmission needs of the transmission planning region.[2224] The Commission

NYSERDA Initial Comments at 8, 11–12; Pennsylvania Commission Initial Comments at 4–5; PJM Initial Comments at 59–62; TANC Initial Comments at 10).

[2217] Dominion Reply Comments at 8 (citing PIOs Initial Comments at 13, 28; NARUC Initial Comments at 5–6, 39).

[2218] PJM Reply Comments at 36–37.

[2219] Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

[2220] PIOs Initial Comments at 12–13.

[2221] *See, e.g.,* ISO–NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO–NE Initial Comments at 35–36); SERTP Sponsors Initial Comments at 5.

[2222] Clean Energy Associations Initial Comments at 10.

[2223] R Street Initial Comments at 10.

[2224] NOPR, 179 FERC ¶ 61,028 at P 247 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 442). The Commission also stated in Order No. 1000–A that, as part of the ongoing monitoring of the progress of a transmission facility once it is selected, the transmission providers in a transmission planning region must establish a date

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proposed that, to the extent the Relevant State Entities in a transmission planning region agree to a State Agreement Process, as described in the Regional Transmission Cost Allocation section, the development schedule should also include relevant steps related to that process.[2225]

1034. The Commission noted that, given the longer-term nature of transmission needs driven by changes in the resource mix and demand, the required development schedule for a transmission facility selected may make it unnecessary for the developer to take actions or incur expenses in the near-term if the transmission facility will not need to be in service in the near-term. The Commission also noted that a transmission provider may make that Long-Term Regional Transmission Facility's selection status subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles, such that the previously selected transmission facility is no longer needed. The Commission proposed that transmission providers include in their selection criteria how they will address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2226]

b. Comments

1035. Some commenters argue that the Commission should allow or require transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2227] For example, Kansas Commission contends that transmission providers should be able to de-select any transmission facility selected through Long-Term Regional Transmission Planning if other regional transmission planning processes do not establish a need for that transmission facility.[2228] Illinois Commission argues that periodic review and revision of the underlying modeling assumptions incorporated in Long-Term Scenarios will help to ensure that Long-Term Regional Transmission Planning allows transmission providers the opportunity to modify regional transmission plans.[2229]

1036. APPA supports the NOPR proposal, stating that ''off ramps'' from Long-Term Regional Transmission Planning are necessary to protect customers from the costs of transmission facilities that are rendered unneeded or inefficient by material changes in available resources, technology, load characteristics, or laws.[2230] APPA continues that the Commission should also require transmission providers to include in their selection criteria how they will address the selection status of previously selected transmission facilities in subsequent transmission planning cycles. APPA further argues that, to facilitate such review, the Commission should require transmission providers to have clear mechanisms for tracking costs and benefits of Long-Term Regional Transmission Facilities and to file periodic cost tracking reports with the Commission so that stakeholders have an opportunity to comment.[2231]

1037. LS Power argues that transmission providers should perform ''variance analyses'' of all previously selected regional transmission facilities.[2232] LS Power contends that all variations in costs, from the initial regional planning estimate through project completion, should be maintained in a single publicly available database.[2233]

1038. Certain TDUs argue that the Commission should require each transmission provider, at the time it selects a transmission facility that is expected to be in service more than three years later, (1) to identify the key assumptions that drove its inclusion in the regional transmission plan and (2) to review triennially whether those key assumptions remain valid or have materially changed. To promote customer affordability by avoiding over-building or under-building transmission facilities, Certain TDUs contend that if these key assumptions have materially changed, the Commission should require transmission providers to evaluate whether any revisions are necessary with respect to such transmission facilities.[2234]

1039. Large Public Power argues that, following selection of transmission facilities in Long-Term Regional Transmission Planning, the Commission should require transmission providers to create a cost and risk management framework. Specifically, Large Public Power argues that the Commission should require transmission providers to develop and implement protocols requiring the developer of a transmission facility to file periodic reports with the Commission tracking anticipated project costs against cost projections and updating benefits information. In the period before construction begins, if such reports indicate that anticipated costs have exceeded an identified threshold, or that benefit-cost ratios have declined by an identified percentage, Large Public Power states that stakeholders could consider remedial action and the transmission developer could present stakeholders with mitigation plans. Further, if stakeholders do not reach consensus on the developer's mitigation plan, Large Public Power argues that stakeholders could petition the Commission to disallow regional cost allocation for the transmission facility. Finally, under Large Public Power's proposal, if the Commission disallowed regional cost allocation, the transmission developer would be eligible for abandoned plant cost recovery in the absence of imprudence.[2235]

1040. Large Public Power argues that its proposal would provide more protection to consumers than did Order No. 1000. Large Public Power further contends that its proposal is similar to, but more expansive than, MISO's existing variance analysis process, and that it would work together with the Commission's proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.[2236] APPA agrees with Large Public Power's proposal and argues that all interested stakeholders should have the opportunity to participate in any

by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the facility is selected to address. If such critical steps have not been achieved by that date, then the transmission providers in a transmission planning region may ''remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.'' Order 1000–A,139 FERC ¶ 61,132 at P 442.

[2225] NOPR, 179 FERC ¶ 61,028 at P 247.

[2226] *Id.* P 248.

[2227] *See, e.g.,* Ameren Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[2228] Kansas Commission Initial Comments at 14.

[2229] Illinois Commission Initial Comments at 6.

[2230] APPA Initial Comments at 22 (citing APPA ANOPR Initial Comments at 9–10; APPA ANOPR Reply Comments at 4; APPA, et al., Statement of Bryce Nielsen, Docket No. RM21–17–000, at 2 (filed Nov. 12, 2021)).

[2231] *Id.* at 35–36.

[2232] LS Power Supplemental Comments at 13–15.

[2233] *Id.* at 13.

[2234] Certain TDUs Initial Comments at 20.

[2235] Large Public Power Initial Comments at 11–12.

[2236] *Id.* (citing NOPR, 179 FERC ¶ 61,028 at P 248; Order No. 1000, 136 FERC ¶ 61,051 at PP 7, 263, 329; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0)).

process to reassess previously approved transmission projects.[2237]

1041. New York Commission and NYSERDA state that, while transmission providers can identify transmission needs using a 20-year transmission planning horizon, transmission facilities should be selected closer in time to when the need is anticipated to materialize. New York Commission and NYSERDA state the final order should direct transmission providers to develop ''off ramps'' in Long-Term Regional Transmission Planning so that previously identified Long-Term Regional Transmission Facilities can be reevaluated as the facility's needed-by date approaches. New York Commission and NYSERDA state that conducting ongoing review can help reduce the risk of stranded costs.[2238]

1042. NRECA contends that selecting transmission projects 20 years in advance is not necessary or even workable. NRECA contends that under the Commission's proposal, transmission providers would select Long-Term Regional Transmission Facilities conditionally and wait until a subsequent Long-Term Regional Transmission Planning cycle to confirm that selection decision, at which point the transmission developer would become eligible to use the applicable regional cost allocation method. NRECA argues that the Commission should allow a transmission provider during such a subsequent cycle to find that a previously selected transmission facility is no longer needed, either because the transmission need no longer exists or because the facility is no longer the most efficient or cost-effective solution to meet the need.[2239]

1043. ISO–NE takes no position on the Commission's proposal but argues that the Commission should allow transmission providers the flexibility to determine the treatment of previously selected transmission projects based on outcomes of subsequent Long-Term Regional Transmission Planning cycles.[2240]

1044. A number of commenters oppose or express concerns with the Commission's proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles. For example, AEP argues that, once selected through Long-Term Regional Transmission Planning, transmission providers should include transmission facilities in future scenario analysis except where a new study raises serious doubt that the transmission facilities continue to provide net benefits. AEP contends that re-studying such transmission facilities will lead to an endless cycle of study and ultimately underinvestment in necessary transmission infrastructure, as well as increased costs for customers.[2241] Similarly, Indicated PJM TOs argue that, once selected, transmission facilities should remain in the regional transmission plan unless there is serious doubt a transmission facility would provide net benefits.[2242]

1045. Avangrid argues that there must be a high bar in subsequent Long-Term Regional Transmission Planning cycles for removing a previously selected transmission facility from the regional transmission plan because transmission developers must have confidence that selection in Long-Term Regional Transmission Planning represents a ''definitive directive[ ] to invest capital.'' [2243] Avangrid states that transmission facilities should not be de-selected unless there are changed circumstances that would make continued development of the project materially detrimental. Avangrid argues that otherwise, Long-Term Regional Transmission Planning effectively will be an informational exercise on which investors cannot rely.[2244]

1046. Eversource recommends that the Commission clarify that once transmission facilities are selected in a Long-Term Regional Transmission Planning cycle, they will not be subject to reevaluation, because such reevaluation would undermine the transmission planning process and deter transmission investment that the Commission is seeking to encourage.[2245] Similarly, Exelon argues that the Commission should clarify that the selection of transmission facilities identified in Long-Term Regional Transmission Planning should be a conclusive action that is reasonably final and on which transmission developers can rely. Exelon explains that Long-Term Regional Transmission Facilities are likely to be high-voltage backbone facilities that meaningfully impact power flows on the transmission system and argues that restudy or reconsideration should be the exception and not the rule, allowing for their inclusion in system planning models used for other purposes (*e.g.,* regional transmission planning addressing reliability and economic transmission needs and generator interconnection studies).[2246]

1047. WIRES contends that the Commission should clarify that transmission providers need not reevaluate previously selected Long-Term Regional Transmission Facilities after updating Long-Term Scenarios. WIRES claims that doing so would disrupt transmission facility development and raise costs.[2247] Similarly, PPL argues that the Commission should exempt transmission facilities that are under construction or for which equipment has been purchased from any reevaluation in subsequent Long-Term Regional Transmission Planning cycles.[2248] Invenergy argues that while Long-Term Scenarios should be regularly reassessed and updated, these updates should apply only to future Long-Term Regional Transmission Planning cycles and should not result in re-assessment of previously selected transmission facilities.[2249]

c. Commission Determination

1048. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to include in their OATTs provisions that require them—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected. These OATT provisions must meet the requirements set forth below, as well as the minimum requirements for transmission providers' broader evaluation process and selection criteria described above in the Minimum Requirements section.

1049. Specifically, we direct transmission providers to revise their OATTs to require reevaluation of any selected Long-Term Regional Transmission Facilities in the following three situations, subject to limitations that we set forth below: (1) delays in the development of a previously selected Long-Term Regional Transmission Facility would jeopardize a transmission provider's ability to meet its reliability needs or reliability-related service obligations; [2250] (2) the actual or

[2237] APPA Reply Comments at 11–12 (citing Large Public Power Initial Comments at 11–12).

[2238] New York Commission and NYSERDA Initial Comments at 12.

[2239] NRECA Initial Comments at 25–26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[2240] ISO–NE Initial Comments at 36.

[2241] AEP Initial Comments at 13–14.

[2242] Indicated PJM TOs Initial Comments at 11.

[2243] Avangrid Initial Comments at 11.

[2244] *Id.*

[2245] Eversource Initial Comments at 15–16.

[2246] Exelon Initial Comments at 17–18.

[2247] WIRES Initial Comments at 7.

[2248] PPL Initial Comments at 6.

[2249] Invenergy Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028 at app. B).

[2250] We note that this is the same as the requirement adopted in Order No. 1000. *See* Order

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projected costs of a previously selected Long-Term Regional Transmission Facility significantly exceed cost estimates used in the selection of a Long-Term Regional Transmission Facility; or (3) significant changes in Federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission providers' selection criteria.[2251]

1050. In addition, we require transmission providers to include specific criteria in their OATTs that they will use to determine when one of these three situations occurs, thereby triggering the reevaluation of a previously selected Long-Term Regional Transmission Facility. For example, with respect to exceeding cost estimates (the second situation listed above), transmission providers may propose a specific threshold of cost escalation (*e.g.,* a percent of total facility cost) above which the transmission providers would reevaluate a previously selected Long-Term Regional Transmission Facility. As another example, with respect to delays (the first situation listed above), transmission providers may propose specific development milestones that, if missed, may jeopardize the transmission developer's schedule and ultimately a transmission provider's ability to meet its reliability needs or reliability-related service obligations. We provide transmission providers with flexibility to propose these criteria on compliance, subject to the requirement that, as with the transmission providers' selection criteria, the reevaluation criteria must seek to maximize benefits accounting for costs over time without over-building transmission facilities. As such, in establishing such criteria, we expect transmission providers will balance the need to provide transmission developers with adequate investment certainty, absent which more efficient or cost-effective Long-Term Regional Transmission Facilities will not be developed, against the risk that, due to significant changes in circumstances, failing to reevaluate a selected Long-Term Regional Transmission Facility may result in the over-building of transmission. In addition, transmission providers must designate a point after which all selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation, such that the transmission developer of the selected Long-Term Regional Transmission Facility has adequate certainty to make investment decisions, *e.g.,* when the facility's transmission developer has secured all relevant permits and authorizations for the Long-Term Regional Transmission Facility.

1051. Further, as discussed further below, transmission providers may not reevaluate any selected Long-Term Regional Transmission Facility on the basis of significant changes in Federal, federally recognized-Tribal, state, or local laws or regulations unless, during the Long-Term Regional Transmission Planning cycle in which transmission providers selected the Long-Term Regional Transmission Facility, the Long-Term Regional Transmission Facility's targeted in-service date was in the latter half of the 20-year transmission planning horizon for Long-Term Regional Transmission Planning.

1052. We also require transmission providers to include in the reevaluation provisions in their OATTs the process and procedures that they will use to reevaluate a previously selected Long-Term Regional Transmission Facility, including the potential outcomes of reevaluation (*e.g.,* taking no action, imposing a mitigation plan, reassigning the Long-Term Regional Transmission Facility to a different transmission developer, modifying the Long-Term Regional Transmission Facility, removing the Long-Term Regional Transmission Facility from the regional transmission plan).[2252] In particular, transmission providers must describe the conditions under which they would remove a previously selected Long-Term Regional Transmission Facility from the regional transmission plan.[2253] We provide flexibility to transmission providers to propose such processes and procedures, subject to the following requirements. First, reevaluation on the basis of cost increases or significant changes in Federal, federally-recognized Tribal, state, or local laws or regulations must be part of a subsequent Long-Term Regional Transmission Planning cycle following selection and must take into account not only the updated costs but also the updated benefits of the Long-Term Regional Transmission Facility.[2254] Second, in order to allow for reevaluation to occur, these processes and procedures must include mechanisms for tracking costs so that transmission providers have an accurate way to determine if the actual or projected costs of the previously selected Long-Term Regional Transmission Facility exceed cost estimates by the relevant threshold, therefore requiring transmission providers to reevaluate that Long-Term Regional Transmission Facility. Third, the reevaluation processes and procedures must seek to maximize benefits accounting for costs over time without over-building transmission facilities. Again, we expect transmission providers in establishing these processes and procedures, including potential mitigation measures, to consider outcomes that enable more efficient or cost-effective Long-Term Regional Transmission Facilities to be developed, while addressing the risk of over-building.

1053. We note that in setting forth these requirements, we have carefully reviewed the record developed here and weighed commenters' countervailing arguments. We believe that the reevaluation requirements set forth above strike a careful balance between two broad objectives of Long-Term Regional Transmission Planning. On the one hand, we believe that transmission providers must have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities, which requires sufficiently long-term, forward-looking, and comprehensive regional transmission planning practices. Moreover, for selection to meaningfully result in the development of such more efficient or cost-effective Long-Term Regional

No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000–A, 139 FERC ¶ 61,132 at P 442; NOPR, 179 FERC ¶ 61,028 at P 247 & n.395.

[2251] NOPR, 179 FERC ¶ 61,028 at P 248.

[2252] *See, e.g.,* MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § IX.E (setting forth potential outcomes of MISO's variance analysis procedures). Mitigation plans would provide to transmission developers the opportunity to address the cause of the reevaluation. For example, where reevaluation occurs because there are delays in the development of a previously selected Long-Term Regional Transmission Facility, transmission providers might require the transmission developer to develop an operating procedure to ensure that the transmission providers are able to address the reliability need or meet the reliability-related service obligation in the period before the Long-Term Regional Transmission Facility will be placed in service.

[2253] We note that, in the event that the Long-Term Regional Transmission Facility was subject to competitive processes when it was selected, we do not require transmission providers to re-conduct these competitive processes in the event that the reevaluation process results in a change to the scope of the Long-Term Regional Transmission Facility. Instead, transmission providers have the flexibility to propose on compliance and explain whether, and if so when, they will re-run the competitive transmission development process as part of the reevaluation process.

[2254] Further, to perform the reevaluation analysis, we expect that transmission providers will use the updated Long-Term Scenarios and associated transmission system models that are developed for the Long-Term Regional Transmission Planning cycle in which the transmission provider reevaluates the selected Long-Term Regional Transmission Facility.

Transmission Facilities, it must provide adequate certainty to transmission developers to support capital investment.

1054. On the other hand, we also acknowledge the inherent uncertainty involved in predicting future transmission needs, and the continued selection of Long-Term Regional Transmission Facilities that no longer meet the transmission providers' selection criteria closer to the time that those facilities are expected to go into service could be costly for consumers. Where transmission providers have selected Long-Term Regional Transmission Facilities further out in the transmission planning horizon, and where transmission providers timely obtain updated information about significant changes to the costs or benefits of such facilities, we believe that transmission providers must, consistent with the requirements in this final order, reevaluate a selected Long-Term Regional Transmission Facility in order to ensure that the facility continues to meet the transmission providers' selection criteria.

1055. In the NOPR, the Commission attempted to balance these objectives by proposing that, because the required development schedule of a previously selected Long-Term Regional Transmission Facility may not require its transmission developer to take actions or incur expenses in the near-term, transmission providers might be able to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.[2255] On further reflection, however, and after reviewing comments submitted in response to the NOPR,[2256] we find that conditioning the selection of a Long-Term Regional Transmission Facility in this manner and on a routine basis may introduce too much uncertainty into transmission providers' evaluation and selection of Long-Term Regional Transmission Facilities.[2257] We agree with AEP that routine reevaluation would require repeated studies and ultimately could lead to underinvestment in Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.[2258] Therefore, we do not adopt the NOPR proposal to allow transmission providers to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.

1056. Nevertheless, we continue to believe that transmission providers may be reticent to select—and Relevant State Entities and other stakeholders may not support the selection of—certain Long-Term Regional Transmission Facilities in the absence of a requirement for transmission providers to reevaluate the selection of such facilities should significant new information become available that could give rise to concerns that those facilities no longer meet the transmission providers' selection criteria.[2259] Further, as is required for regional transmission planning processes under Order No. 1000, transmission providers also must have the ability to take action when delays in developing a Long-Term Regional Transmission Facility risk jeopardizing a transmission provider's ability to meet its reliability needs or reliability-related service obligations.[2260]

1057. As discussed above, selection of a Long-Term Regional Transmission Facility is only one step in the process of developing, constructing, and placing that facility in service for the benefit of customers. Given the risks involved in transmission development, it is necessary to provide sufficient certainty to transmission developers and their financing partners that reevaluation will not lead to endless studies and protracted dispute. Therefore, we require transmission providers to set forth in their OATTs a reevaluation process, as outlined above, that ensures that any reevaluation of Long-Term Regional Transmission Facilities that have been selected will occur only in the circumstances that we have described.

1058. We agree with APPA that reevaluation—and in particular any determination of whether a Long-Term Transmission Need continues to exist or whether a Long-Term Regional Transmission Facility continues to meet the transmission providers' selection criteria—will require transmission providers to be able to track the costs of developing Long-Term Regional Transmission Facilities.[2261] We note above that transmission providers must propose on compliance the mechanism that they will use to track the costs of selected Long-Term Regional Transmission Facilities.

1059. As discussed above, however, we note that, when conducting a reevaluation of a selected Long-Term Regional Transmission Facility, transmission providers must update not only actual and projected costs but also their calculation of the benefits of the selected Long-Term Regional Transmission Facility. Such a requirement will ensure that transmission providers are comparing the relevant costs and benefits, *i.e.,* the updated costs and benefits of the selected Long-Term Regional Transmission Facility, to determine whether the Long-Term Regional Transmission Facility continues to be a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. Because updating the calculation of the benefits of a Long-Term Regional Transmission Facility is not as straightforward as tracking costs, we require reevaluation on the basis of cost escalations or of changes in Federal, federally-recognized Tribal, state, or local laws and regulations to occur as part of a subsequent Long-Term Regional Transmission Planning cycle. We find that this requirement is appropriate given the substantial time and resources that we expect will be necessary to update the underlying assumptions used in the transmission planning models, which must take place in order to update the calculation of the benefits of selected Long-Term Regional Transmission Facilities for purposes of such reevaluations. Requiring transmission providers to update these assumptions and their transmission planning models, including all Long-Term Scenarios and any associated sensitivities, beyond a subsequent Long-Term Regional Transmission Planning cycle would introduce unnecessary disruptions and potentially impede the efficient conduct of the next Long-Term Regional Transmission Planning cycle.

1060. In response to Kansas Commission, we decline to allow transmission providers to remove a Long-Term Regional Transmission Facility from a regional transmission

[2255] NOPR, 179 FERC ¶ 61,028 at P 248.

[2256] *See, e.g.,* Exelon Initial Comments at 17–18 (arguing that selection should be ''reasonably final'' and that routine reevaluation would harm the certainty required for developing Long-Term Regional Transmission Facilities, inhibit efficient interconnection queue processing, and undermine system reliability as a whole).

[2257] For this reason, we are unpersuaded by NRECA's argument that transmission providers should conditionally select Long-Term Regional Transmission Facilities subject to confirmation in a subsequent Long-Term Regional Transmission Planning cycle. NRECA Initial Comments at 25–26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[2258] *See* AEP Initial Comments at 13–14.

[2259] *See, e.g.,* APPA Initial Comments at 22 (arguing that there should be ''off ramps'' protecting transmission customers from Long-Term Regional Transmission Facilities that, following selection, are rendered unnecessary or inefficient by intervening changes (citations omitted)).

[2260] Order No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000–A, 139 FERC ¶ 61,132 at P 442.

[2261] APPA Initial Comments at 36.

plan for purposes of cost allocation solely because other regional transmission planning processes do not establish a need for that transmission facility.[2262] Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes identify transmission needs differently, and we do not agree based on the requirements that we establish in this final order for Long-Term Regional Transmission Planning that reevaluation based solely on transmission needs identified through existing Order No. 1000 regional transmission planning processes is appropriate. We also decline Certain TDUs' request that the Commission require transmission providers to identify certain key assumptions driving the selection of Long-Term Regional Transmission Facilities and to review these assumptions in subsequent Long-Term Regional Transmission Planning cycles. Long-Term Regional Transmission Planning will necessitate that transmission providers compile a wide range of information from multiple data sources, analyze the effect of that information, develop Long-Term Scenarios that provide a view into what Long-Term Transmission Needs may be, and evaluate Long-Term Regional Transmission Facilities in light of these multiple different scenarios. In this light, we believe that Certain TDUs' suggested approach would not capture the complex interactions of the various factors giving rise to Long-Term Transmission Needs.

1061. Finally, we note that a coalition of diverse interests, including transmission developer, utility, and consumer interests, jointly expressed support for a framework that would provide for reconsideration of a Long-Term Regional Transmission Facility where cost and benefit projections deviate substantially from those at the time of selection.[2263] We appreciate such efforts to bridge divergent interests to find common ground in a compromise proposal, and believe that the reevaluation requirements adopted here, like that widely supported compromise, strike a balance between competing interests.

[2262] *See* Kansas Commission Initial Comments at 14.

[2263] *See Advocates Advance Transmission Planning Cost Management Proposal At FERC,* Large Public Power Council (Mar. 6, 2024), *https://www.lppc.org/news/lppc-and-advocacy-groups-advance-transmission-planning-cost-management-proposal-at-ferc* (describing endorsements by LPPC, ACEG, CEBA, and NASUCA).

F. Implementation of Long-Term Regional Transmission Planning

1. NOPR Proposal

1062. In the NOPR, the Commission proposed to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning efforts. The Commission stated that it recognized the possibility that there may be overlap in the time horizon for the proposed Long-Term Regional Transmission Planning and existing near-term regional transmission planning processes and that they will likely inform each other.[2264] The Commission also stated that it is possible that, in some cases, transmission facilities selected to address transmission needs driven by changes in the resource mix and demand may provide near-term reliability or economic benefits, and thus potentially displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.

1063. In the NOPR, the Commission also sought comment on whether the Commission should host a periodic forum for transmission providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.[2265]

2. Comments

a. Comments on the Initial Timing Sequence

1064. Several commenters support requiring transmission providers to explain on compliance how Long-Term Regional Transmission Planning will interact with existing Order No. 1000 regional transmission planning processes.[2266] Several commenters urge the Commission to allow regional flexibility with respect to coordination between existing Order No. 1000 regional transmission planning processes and Long-Term Regional Transmission Planning.[2267] NESCOE argues that it could be counterproductive and unnecessary for the Commission to dictate the initial timing of new processes to coordinate them with existing Order No. 1000 regional transmission planning processes.[2268] PPL stresses the need for clarity on how the existing Order No. 1000 regional transmission planning processes interacts with Long-Term Regional Transmission Planning and states that each transmission planning region will need to address how planned reliability and economic projects should or should not be reflected in, evaluated against, and affected by long-term studies.[2269]

1065. R Street states that the NOPR correctly identifies challenges in harmonizing existing Order No. 1000 and Long-Term Regional Transmission Planning. R Street argues that the two processes should use different time frames and assumptions, with timing optimized to account for uncertainty. R Street maintains that existing Order No. 1000 transmission planning should be conducted annually over a transmission planning horizon of up to five years and should account for only those generators that are existing, under construction, or have interconnection agreements. R Street states that Long-Term Regional Transmission Planning should be conducted every two or three years over a 20-year transmission planning horizon and should account for representative generation development expectations and longer-term load growth. R Street posits that the long-term process should then feed into the near-term process, and transmission projects failing a cost-benefit test in one transmission planning cycle can roll over to the next in-kind cycle.[2270]

1066. PIOs contend that the different timing for Order No. 1000 transmission planning process cycles across transmission planning regions can create inconsistent assumptions, uncoordinated project identification between the two processes, confusion, and administrative burden.[2271] To address this concern, PIOs assert that the Commission should: (1) mandate Order No. 1000 regional transmission planning process cycles be no longer than Long-Term Regional Transmission Planning cycles and if shorter, divide Long-Term Regional Transmission Planning cycles evenly;[2272] (2) synchronize assumptions so that assumptions are identical for years

[2264] NOPR, 179 FERC ¶ 61,028 at P 253.

[2265] *Id.* P 255.

[2266] Ameren Initial Comments at 22–23; APPA Initial Comments at 5, 24–25; Idaho Commission Initial Comments at 5; National Grid Initial Comments at 19; NYISO Initial Comments at 13.

[2267] Ameren Initial Comments at 22–23; Duke Initial Comments at 29; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51–52; NYISO Initial Comments at 13; Pacific Northwest State Agencies Initial Comments at 20.

[2268] NESCOE Initial Comments at 51–52.

[2269] PPL Initial Comments at 4.

[2270] R Street Initial Comments at 10–11.

[2271] PIOs Initial Comments at 47.

[2272] As an example, if a transmission provider uses a 36-month Long-Term Regional Transmission Planning cycle, its Order No. 1000 transmission planning cycles should be 36, 18, or 12 months. *Id.*

where both a Long-Term Regional Transmission Planning cycle and an existing Order No. 1000 regional transmission planning cycle start; (3) clarify the time period for existing Order No. 1000 regional transmission planning for economic and reliability needs; and (4) require transmission providers to clarify when results of one transmission planning process are incorporated into another, and require reasonable efforts to avoid one process disrupting the other.[2273]

b. Comments on Periodic Forums

1067. Several commenters support the Commission's proposal to host a periodic forum for transmission providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.[2274] For example, AEP states that periodic forums would allow stakeholders to discuss best available data, modeling inputs, and techniques for calculating benefits.[2275] GridLab states that a periodic forum, along with follow-on technical conferences and a periodic forum, could promote greater convergence in planning methods among transmission providers.[2276]

1068. Pacific Northwest State Agencies suggest that the Commission could hold technical conferences or regional sessions similar to the Federal State Task Force on Electric Transmission.[2277] In contrast, PJM states that the periodic forum should be less formal than the technical conference format and that the Commission should consider using existing interconnection-wide organizations to host some of these forums.[2278] SPP also notes that there are existing forums that could be leveraged, such as the Eastern Interconnection Planning Collaborative.[2279]

1069. Some commenters recommend that the forums be held on an annual or a triennial schedule.[2280] MISO notes that, while the current pace of change might warrant multiple technical discussions to understand emerging trends, over the long term such technical forums may only be necessary when new industry trends are identified.[2281] Nevada Commission and Northwest and Intermountain suggest that the forum could be structured into two parts, separated by policy and technical discussion, by RTOs/ISOs and OATT transmission planning regions, or by Eastern and Western Interconnection.[2282]

1070. Dominion and Idaho Power oppose the Commission hosting additional periodic forums.[2283] Dominion recommends that the Commission use the existing Joint Federal-State Task Force on Electric Transmission instead.[2284] Idaho Power asserts that the most useful approach would be to allow transmission planning regions the time necessary to formulate processes that meet the Commission's requirements, and additional time for implementation and integration of those processes into current transmission planning processes.[2285]

3. Commission Determination

a. Initial Timing Sequence Implementation

1071. We adopt the NOPR proposal to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. Transmission providers must provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, we find that transmission providers must address the possible interaction between the transmission planning cycle for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. As the Commission stated in the NOPR, we recognize the possibility that there may be overlap in the time horizon for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes and that these processes will likely inform each other. Second, we find that transmission providers must address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. As the Commission noted in the NOPR, it is possible that, in some cases, Long-Term Regional Transmission Facilities selected to address Long-Term Transmission Needs may provide near-term reliability or economic benefits, and thus could displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.[2286]

1072. We find that transmission providers should have the flexibility to integrate the existing regional transmission planning processes with Long-Term Regional Transmission Planning in a manner that mitigates the potential for disruption of the existing regional transmission planning processes, and we note the agreement of some commenters on this point.[2287] However, we are also concerned that too much flexibility for transmission providers with respect to the date by which they must begin the first Long-Term Regional Transmission Planning cycle could lead to unnecessary delay in realizing these beneficial reforms for customers. Thus, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. However, we understand that it will likely be useful to align in some manner the Long-Term Regional Transmission Planning cycle with existing transmission planning cycles. In some cases, such alignment may not be possible to do within this one-year deadline. Therefore, transmission providers in a transmission planning region may propose to start the first Long-Term Regional Transmission Planning cycle on a date later than one year from the initial compliance filing due date, only to the extent needed to

[2273] *Id.* at 48–49.

[2274] ACORE Initial Comments at 15; AEP Initial Comments 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19–20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35–36.

[2275] AEP Initial Comments at 31.

[2276] GridLab Initial Comments at 5.

[2277] Pacific Northwest State Agencies Initial Comments at 20.

[2278] PJM Initial Comments at 77.

[2279] SPP Initial Comments at 24.

[2280] AEP Initial Comments at 31; Arizona Commission Initial Comments at 9; Nevada Commission Initial Comments at 12.

[2281] MISO Initial Comments at 57.

[2282] Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17.

[2283] Dominion Initial Comments at 15–16; Idaho Power Initial Comments at 8–9.

[2284] Dominion Initial Comments at 15–16.

[2285] Idaho Power Initial Comments at 8–9.

[2286] NOPR, 179 FERC ¶ 61,028 at P 253.

[2287] Ameren Initial Comments at 22–23; Anbaric Initial Comments at 4–5, 22–27; CAISO Initial Comments at 2–3, 9, 17–20; Duke Initial Comments at 29; Indicated PJM TOs Initial Comments at 12; Large Public Power Initial Comments at 14–16; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51–52; NYISO Initial Comments at 13; PPL Initial Comments at 4; Pacific Northwest State Agencies Initial Comments at 20; Transmission Dependent Utilities Initial Comments at 4–5.

align transmission planning cycles. While we encourage transmission providers to align transmission planning cycles if useful, to ensure that there is no inappropriate delay to starting Long-Term Regional Transmission Planning, transmission providers in a transmission planning region that propose a commencement date of later than one year from the compliance due date must include adequate support explaining how the proposed date to begin the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region.

1073. In addition, we recognize commenters' concerns regarding the coordination of Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning processes, and we encourage transmission providers to address in their explanation how their proposed Long-Term Regional Transmission Planning would facilitate moving beyond piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.[2288]

1074. With respect to the argument by NESCOE that it would be counterproductive and unnecessary for the Commission to dictate the initial timing of new processes,[2289] we disagree. We find that it is necessary to establish a requirement for transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due (subject to the limited exception described above), on which they will commence the first Long-Term Regional Transmission Planning Cycle, in order to guarantee that implementation will not be subject to unreasonable or unnecessary delay. With regard to the proposals made by PIOs and R Street,[2290] we decline to adopt these proposals because we lack the record to assess the impacts that these more prescriptive proposed requirements would have on existing transmission planning processes, and whether these proposals would work effectively across the differing transmission planning processes in each transmission planning region.

b. Periodic Forums

1075. We believe that it will be beneficial for the Commission to host a periodic forum for transmission providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning, and note commenters' agreement on this point.[2291] Accordingly, the Commission will organize forums to share best practices in implementing Long-Term Regional Transmission Planning and provide notice and relevant details in advance of the forums.

IV. Coordination of Regional Transmission Planning and Generator Interconnection Processes

A. Need for Reform and Overall Reform

1. NOPR Proposal

1076. In the NOPR, the Commission proposed to require that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s).[2292]

1077. The Commission preliminarily found that this requirement will support the establishment of just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates by addressing a potential barrier to integrating new sources of generation that may otherwise continue to exist absent such requirement in the regional transmission planning process.[2293] As the Commission explained in the NOPR, the interaction between regional transmission planning and cost allocation processes and the generator interconnection process is limited—the baseline regional transmission planning models generally only incorporate interconnection projects that have completed an interconnection facilities study and are therefore near the end of the generator interconnection process.[2294] The Commission stated, however, that where transmission system needs are repeatedly identified through generator interconnection processes, more efficient or cost-effective transmission expansion could be achieved through regional transmission planning and cost allocation that allocates costs in a manner that is at least roughly commensurate with estimated benefits and eliminates a potential barrier to entry for new generation resources.[2295]

1078. Additionally, the Commission sought comment on how the proposed requirement to evaluate such facilities for selection should interact with existing regional transmission planning processes and Long-Term Regional Transmission Planning.[2296]

2. Comments

a. On the Overall Reform

1079. Multiple commenters express support for the general notion of coordinating the transmission planning and generator interconnection processes.[2297] Other commenters explicitly support the coordination proposal laid out in the NOPR,[2298] with some of these commenters arguing that the NOPR proposal does not go far enough (as described below).[2299]

1080. Other commenters offer more qualified support for the NOPR proposal. APPA and Exelon see value in the proposal but emphasize that any interconnection-related network upgrades that meet the specified criteria must independently satisfy any other applicable criteria for selection.[2300] Similarly, NRECA requests that the Commission clarify that interconnection-related network upgrades associated with withdrawn interconnection requests will not receive preferential treatment in Long-Term Regional Transmission Planning.[2301] Clean Energy Associations and ENGIE support the proposal but argue that the Commission's concern could be more efficiently addressed

[2288] *See supra* Need for Reform section.

[2289] NESCOE Initial Comments at 51–52.

[2290] PIOs Initial Comments at 44–48; R Street Initial Comments at 10–11.

[2291] ACORE Initial Comments at 15; AEP Initial Comments 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19–20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35–36.

[2292] NOPR, 179 FERC ¶ 61,028 at P 166.

[2293] *Id.* P 168.

[2294] *Id.* P 155 (citing ANOPR, 176 FERC ¶ 61,024 at P 23).

[2295] *Id.* P 161.

[2296] *Id.* P 174.

[2297] ACEG Initial Comments at 51–53; Clean Energy Buyers Initial Comments at 19; DC and Maryland Office of People's Counsel Initial Comments at 16; Fervo Reply Comments at 1; Handy Law Initial Comments at 8–9; Interwest Initial Comments at 10–11; Invenergy Initial Comments at 2; Ohio Commission Federal Advocate Initial Comments at 8; PIOs Initial Comments at 72–73; R Street Initial Comments at 7–8.

[2298] ACEG Initial Comments at 51–53; California Commission Initial Comments at 27; SDG&E Initial Comments at 3.

[2299] Acadia Center and CLF Initial Comments at 25–26; ACORE Initial Comments at 13.

[2300] APPA Initial Comments at 31; Exelon Initial Comments at 11–13.

[2301] NRECA Reply Comments at 10–11.

with better regional transmission planning.[2302]

b. Requesting Additional Reform

1081. Some commenters suggest that the NOPR proposal does not go far enough to integrate the transmission planning and generator interconnection processes or to improve interconnection-related network upgrade cost allocation.[2303] ACORE argues that more dramatic reforms are necessary.[2304] Anbaric contends that a planning assessment should be conducted whenever an interconnection request triggers interconnection-related network upgrades on the larger transmission system beyond the interconnection substation and associated facilities.[2305] ELCON states that Long-Term Regional Transmission Planning should be integrated with the generator interconnection queue.[2306] It suggests that the Commission hold regular workshops to review best practices for coordinating the interconnection queue, current regional transmission planning, and Long-Term Regional Transmission Planning to reduce interconnection queue backlogs, leading to larger regional transmission projects that would both incorporate interconnection-related transmission needs and be eligible for competitive bidding.[2307]

1082. Similarly, Enel urges the Commission to consolidate the generator interconnection process into the regional transmission planning process to allow transmission providers to jointly assess the benefits, and allocate the costs, of transmission projects that benefit system loads and new generation.[2308] Likewise, Shell suggests that the Commission integrate Long-Term Regional Transmission Planning and generator interconnection processes, requiring the use of the same benefits analysis under the same criteria, including reliability, economic, and public policy needs. Shell asserts that this approach would: increase opportunities to reduce costs to produce power and deliver it to load, unlock economies of scale and scope, improve processing times for generator interconnection requests, address first mover and free-rider risk, and potentially increase states' willingness to participate in cost allocation.[2309]

1083. Acadia Center and CLF argue that the proposal does not fully address shortfalls with the current method for cost allocation associated with interconnection-related network upgrades.[2310] They also express concern that the NOPR proposal would address a limited subset of generator interconnection needs and call for additional changes to better allocate the costs of interconnection-related network upgrades (especially those related to offshore wind development) to regional beneficiaries.[2311] Similarly, PIOs state the current cost allocation for interconnection-related network upgrades violates settled law that requires costs to be allocated both to cost causers and beneficiaries.[2312] Relatedly, Invenergy argues that the most significant factor influencing an interconnection customer's decision to leave the interconnection queue is typically the cost of assigned interconnection-related network upgrades.[2313]

1084. Invenergy also argues that interconnection-related network upgrades would remedy existing issues and should thus be addressed through the regional transmission planning process.[2314] Invenergy asserts that some regions use different dispatch and other assumptions in the regional transmission planning and generator interconnection processes, which can result in persistent system overloads not being addressed through the regional transmission planning process.[2315] Similarly, Concerned Scientists aver that generator interconnection requests could be 10 years old when the NOPR proposal designates the related interconnection-related network upgrades as suitable for consideration in future Long-Term Scenarios.[2316] Concerned Scientists argue that the Commission should require the inclusion in Long-Term Scenarios of interconnection-related transmission needs that the generator interconnection process identified multiple times.[2317]

c. Concerns With the Overall Reform

1085. Some commenters oppose the Commission's proposal.[2318] AEP, Ameren, CAISO, and Utah Division of Public Utilities argue that the proposal is unnecessary.[2319] Duke argues that the Commission's proposal is unnecessarily prescriptive, difficult to implement, and risks introducing significant subjectivity and complex administration into the transmission planning process.[2320] Ameren claims the proposal will result in inefficient regional transmission planning because it will not minimize total cost to end-use customers.[2321]

1086. Vistra argues that the NOPR proposal does not address how the newly created interconnection capacity will be allocated and how the timing and implementation of such upgrades would work.[2322]

1087. MISO contends that the Commission should not adopt prescriptive rules for integrating the generator interconnection and regional transmission planning processes, but instead continue to allow the RTOs/ISOs to develop those processes that best fit their footprint.[2323] MISO argues that expanding the generator interconnection process beyond its current five-year outlook would slow the generator interconnection process.[2324] MISO requests that if the Commission does not eliminate the NOPR proposal, as MISO would prefer, then the requirement should be altered so that transmission providers would only be required to post a list of generator interconnection upgrades that met the defined criteria.[2325]

1088. CAISO disagrees with California Commission's comments that the NOPR proposal could improve CAISO's existing interconnection-related network upgrade provisions because the two processes have significantly different eligibility requirements,

[2302] Clean Energy Associations Initial Comments at 15; ENGIE Initial Comments at 5.

[2303] Anbaric Initial Comments at 7–9; Clean Energy Associations Initial Comments at 25–26; Concerned Scientists Initial Comments at 21–22; ELCON Initial Comments at 13–14; Enel Initial Comments at 4–5; Invenergy Initial Comments at 10–13; Invenergy Reply Comments at 12–13; PIOs Initial Comments at 72–73; Shell Reply Comments at 3–7.

[2304] ACORE Initial Comments at 13.

[2305] Anbaric Initial Comments at 7–8.

[2306] ELCON Initial Comments at 13–14.

[2307] *Id.* at 14–15.

[2308] Enel Initial Comments at 4–5 (citing Enel, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf* (last visited Apr. 2024)).

[2309] Shell Reply Comments at 3, 5, 6–7.

[2310] Acadia Center and CLF Initial Comments at 25–26.

[2311] *Id.* at 25.

[2312] PIOs Initial Comments at 72.

[2313] Invenergy Reply Comments at 14.

[2314] *Id.* at 12.

[2315] *Id.*

[2316] Concerned Scientists Reply Comments at 22.

[2317] *Id.*

[2318] AEP Initial Comments at 6, 18; Ameren Initial Comments at 17; CAISO Initial Comments at 34; Duke Initial Comments at 4; Illinois Commission Initial Comments at 8–9; MISO Initial Comments at 44–47; PJM Initial Comments at 7, 85–86; PPL Initial Comments at 12.

[2319] AEP Initial Comments at 18–20; Ameren Initial Comments at 18; CAISO Initial Comments at 6, 34–35; Utah Division of Public Utilities Initial Comments at 7.

[2320] Duke Initial Comments at 4, 20.

[2321] Ameren Initial Comments at 18.

[2322] Vistra Initial Comments at 33–34.

[2323] MISO Initial Comments at 44; MISO Reply Comments at 28.

[2324] MISO Reply Comments at 29.

[2325] MISO Initial Comments at 45.

purposes, and impacts.[2326] CAISO further argues that the NOPR proposal could require transmission planners to study only outdated interconnection-related network upgrades.[2327]

1089. Mississippi Commission states that interconnection-related network upgrades should focus on reducing costs and providing price signals and not be included in Long-Term Regional Transmission Planning.[2328]

1090. Some commenters argue that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs instead of other reasons [2329] such as the project being uneconomic,[2330] the project having insufficient site control or permitting delays,[2331] the project being speculative,[2332] or some other regulatory or economic factor.[2333]

1091. PJM recommends an alternative proposal for funding generation interconnections in which states play the major role.[2334] Under the PJM proposal, states that want to incent generation interconnections, perhaps to support a renewable portfolio standard, could fund a backbone transmission system to help facilitate these interconnections.[2335]

1092. Invenergy asks the Commission not to consider certain alternative proposals advanced by other commenters.[2336]

d. Cost Allocation

1093. Some commenters oppose the NOPR proposal on the assumption that it could shift the cost for interconnection-related network upgrades from interconnection customers to load.[2337] In addition, PJM states that the Commission's proposal could lead to undue discrimination and would distort the price signal that generator developers should see to make reasonable investment decisions.[2338] Industrial Customers state that generators should be able to recover the costs of interconnection through market revenues if their projects are competitive.[2339] Industrial Customers further argue that under the cost causation principle, a new generator should pay for interconnection-related network upgrades if such upgrades are only required because of the generator's interconnection.[2340] Vistra asserts that, although the proposal shifts costs indirectly, the Commission still must rationally explain its decision to depart from the existing just and reasonable ''but-for'' policy of Order No. 2003.[2341]

1094. Other commenters oppose the Commission's proposed reform because it will increase the cost to serve load. AEP asserts that such a proposal would possibly result in the development of unnecessary transmission infrastructure, which would lead to increased transmission customer costs for no benefit.[2342] Dominion argues that this proposal could result in over-building and excessive rates for transmission customers.[2343] TAPS asks the Commission to clarify that consideration of interconnection-related transmission needs would not foreclose transmission providers from proposing a cost allocation method that is different from the cost allocation for other types of Long-Term Regional Transmission Facilities.[2344]

e. Interconnection Queue Gaming Considerations

1095. Several commenters express concerns that the NOPR proposal would incentivize gaming by interconnection customers to promote development of interconnection-related network upgrades through the regional transmission planning process.[2345] Some commenters claim that the Commission's proposal could create a perverse incentive for interconnection customers to submit and withdraw multiple interconnection requests so that interconnection-related network upgrades can be considered for regional cost allocation,[2346] especially in transmission planning regions with lower thresholds for entering and maintaining a position in the interconnection queue.[2347]

1096. Pennsylvania Commission, Shell, Eversource, and US DOE recommend the Commission modify the NOPR proposal to limit or prevent gaming. Pennsylvania Commission argues that adding more commitments on the part of the interconnection customer or requiring a more thorough analysis of the reasons for withdrawal is an appropriate way of addressing the concern.[2348] Shell states that, to prevent gaming, the Commission should revise its proposal so that an upgrade is only eligible for inclusion in the Long-Term Regional Transmission Plan if it appears in one generator interconnection study cycle over a five-year period.[2349] Eversource asks the Commission to find that submitting and withdrawing interconnection requests simply so that the required interconnection-related network upgrades would be identified twice in the operative period, for example, would violate the Commission's regulations, including but not limited to the duty of candor and the prohibition of market manipulation.[2350] US DOE states that the Commission should strive to ensure that the reforms do not create the potential for gaming by generators, which, absent mitigation, could increase delays and backlogs in the interconnection queue.[2351]

1097. In response, Interwest argues that suggestions that increased coordination would result in gaming assumes that developers know in advance what interconnection-related network upgrades they will be assigned through the interconnection process.[2352] Interwest argues that, given the uncertainty about whether, and when, such a process could apply and result in selection and construction of facilities under Long-Term Regional

[2326] CAISO Reply Comments at 28–29 (citing California Commission Initial Comments at 27).

[2327] *Id.* at 32.

[2328] Mississippi Commission Reply Comments at 9.

[2329] CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

[2330] American Municipal Power Initial Comments at 33–34; Indicated PJM TOs Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2331] Duke Initial Comments at 20–21; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 8; PJM Initial Comments at 88–89.

[2332] Entergy Initial Comments at 25.

[2333] PJM Initial Comments at 89.

[2334] *Id.* at 89–90.

[2335] *Id.* at 90.

[2336] Invenergy Reply Comments at 15 (citing MISO Initial Comments at 45; PJM Initial Comments 85, 90–92).

[2337] APPA Initial Comments at 31; Industrial Customers Initial Comments at 13; NRECA Initial Comments at 41–42 (citation omitted); NRECA Reply Comments at 8–9; PJM Initial Comments at 89–90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

[2338] PJM Initial Comments at 89.

[2339] Industrial Customers Initial Comments at 13–14.

[2340] *Id.* at 21–22.

[2341] Vistra Initial Comments at 9 (citation omitted).

[2342] AEP Initial Comments at 20.

[2343] Dominion Initial Comments at 32.

[2344] TAPS Initial Comments at 13–14.

[2345] Ameren Initial Comments at 18–19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7–8; EEI Initial Comments at 18; Eversource Initial Comments at 23–24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12–13; Shell Initial Comments at 29–30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

[2346] Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33–34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

[2347] EEI Initial Comments at 18.

[2348] Pennsylvania Commission Initial Comments at 9.

[2349] Shell Initial Comments at 30.

[2350] Eversource Initial Comments at 23–24 (citing 18 CFR 35.41; 18 CFR 1c.2)

[2351] US DOE Initial Comments at 27–28.

[2352] Interwest Reply Comments at 5–6 (citing EEI Initial Comments at 18).

Transmission Planning, it would not incentivize gaming.[2353] Similarly, Invenergy argues that developers would have no reasonable expectation that any interconnection-related network upgrade meeting the NOPR criteria ultimately would be selected through the multi-year regional transmission planning process and actually constructed on a timeline that accommodates the developer's generation facility.[2354] If the Commission is concerned about possible gaming, however, Invenergy urges the Commission to revise the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.[2355]

f. Miscellaneous

1098. SEIA asks the Commission to clarify that the phrase ''interconnection-related transmission needs'' would allow transmission providers to include either individual or aggregated transmission solutions that address specific needs.[2356] SEIA asks the Commission to require transmission providers to assume that these interconnection-related network upgrades will be built and include the interconnection-related network upgrades in their Long-Term Regional Transmission Planning.[2357]

1099. Several commenters argue that the reforms issued under Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, will address interconnection-related issues more appropriately than the NOPR proposal.[2358] Some commenters argue that the Commission should defer consideration of the NOPR proposal until the reforms issued under Order No. 2023 are implemented.[2359]

3. Need for Reform

1100. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not adequately consider certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been resolved due to the withdrawal of the underlying interconnection request(s). We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that there is insufficient coordination between the Commission's existing generator interconnection processes and regional transmission planning and cost allocation processes regarding interconnection-related transmission needs that are repeatedly identified in the generator interconnection process. As a result of this deficiency, transmission providers do not currently consider those identified interconnection-related transmission needs in their regional transmission planning processes, nor do they evaluate whether more efficient or cost-effective regional transmission solutions to these needs could be achieved through regional transmission planning processes and cost allocation. Accordingly, we find that existing regional transmission planning and cost allocation processes are insufficient to ensure just and reasonable rates, and we direct the reforms discussed below to address this deficiency.

1101. As explained in the NOPR,[2360] we are concerned about the prevalence of interconnection-related network upgrades being repeatedly identified in the generator interconnection process in multiple interconnection queue cycles during a short period of time (*e.g.,* five years) but not being developed because the interconnection request(s) driving the need for the upgrade are withdrawn. The record indicates that the level of spending on interconnection-related network upgrades has dramatically increased in recent years, escalating the cost of interconnecting new generation to the transmission system.[2361] The evidence also suggests that this trend is leading to more and more interconnection customers withdrawing their interconnection requests in the face of significant costs associated with interconnection-related network upgrades.[2362] For example, between January 2016 and July 2020, 245 generation projects in advanced stages in the MISO generator interconnection process withdrew from the queue, with the project developers citing high interconnection-related network upgrade costs as the primary reason for their withdrawal.[2363] While interconnection customers may choose to withdraw from the interconnection queue for a number of reasons, in recent years, the deciding factor has increasingly become the interconnection customer's ''sticker shock'' at its cost responsibility for interconnection-related network upgrades.[2364]

1102. When interconnection customers withdraw from the interconnection queue, the identified interconnection-related network upgrades associated with those interconnection customers remain unbuilt and the underlying interconnection-related transmission needs go unaddressed. In many cases, when the interconnection-related transmission need is not addressed via development of interconnection-related network upgrades in one interconnection queue cycle, the same interconnection-related transmission need—and oftentimes the same or a substantially similar interconnection-related network upgrade—will appear in subsequent interconnection queue cycles. One study, which analyzed 12 specific interconnection-related network upgrades identified by MISO and SPP, found that SPP identified three of the upgrades in two interconnection queue cycles and one in three interconnection queue cycles, and MISO identified three of the upgrades in two interconnection queue cycles and two in three interconnection queue cycles.[2365] In other words, both SPP and MISO were repeatedly identifying the same interconnection-related network upgrades as interconnection customers withdrew from the interconnection queue, leaving later-in-time interconnection customers to address

[2353] *Id.* at 6.

[2354] Invenergy Reply Comments at 14.

[2355] *Id.* at 14–15.

[2356] SEIA Initial Comments at 14 (citing SPP, *2020 Integrated Transmission Planning Assessment Report,* at 87 (Oct. 27, 2020)).

[2357] *Id.*

[2358] Dominion Reply Comments at 8; Idaho Power Initial Comments at 6–7; Illinois Commission Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15.

[2359] Duke Initial Comments at 20; EEI Initial Comments at 18; Entergy Initial Comments at 24–25.

[2360] NOPR, 179 FERC ¶ 61,028 at PP 161–165.

[2361] *See* ICF Resources, LLC, *Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits,* 2 (Sept. 9, 2021), *https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf* (ICF Sept. 2021 Interconnection Report); Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy,* 14 (2021)), *https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf* (ACEG 2021 Interconnection Report).

[2362] ACEG 2021 Interconnection Report at 17.

[2363] *Id.* (naming the high cost of interconnection-related network upgrades as the fundamental problem that interconnection queue reform has failed to address thus far).

[2364] *See* ACORE ANOPR Comments at 12; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and Intermountain Initial Comments at 14; *see also* Order No. 2023, 184 FERC ¶ 61,054 at P 41; Order No. 2023–A, 186 FERC ¶ 61,199 at P 14.

[2365] ICF Sept. 2021 Interconnection Report at 25–26.

the same interconnection-related transmission needs.

1103. Where interconnection-related transmission needs are repeatedly identified in interconnection studies, the implication may be that the area, despite the potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers, is otherwise desirable for generators to locate (*e.g.,* it is located close to fuel sources). This repeated interest in accessing the transmission system, combined with the lack of available transmission capacity and prohibitive costs of interconnection-related network upgrades, together create a barrier to accessing the transmission system and establish a known interconnection-related transmission need. We find that this barrier to entry can hinder the timely development of new generation, thereby stifling competition in wholesale electricity markets and limiting access to lower-cost generation.[2366] We find that existing regional transmission planning processes do not adequately consider or account for this specific set of interconnection-related transmission needs that go unaddressed in the generator interconnection processes. By failing to consider such interconnection-related transmission needs, the regional transmission planning process is unable to identify the more efficient or cost-effective regional transmission solutions.

1104. Moreover, the Commission has long recognized that interconnection-related network upgrades provide transmission benefits that extend beyond the interconnection customer.[2367] By upgrading the transmission system in a piecemeal fashion through the generator interconnection process, as described above, the current regional transmission planning paradigm can impose costs on interconnection customers for transmission facilities that provide benefits beyond those received by the interconnection customer. This paradigm allocates transmission costs in a way that may not be roughly commensurate with the distribution of benefits, a result that can lead to unjust and unreasonable rates. The reform adopted below requires the consideration of regional transmission facilities to meet interconnection-related transmission needs repeatedly identified in the generator interconnection process in the Order No. 1000 regional transmission planning and cost allocation processes, which we believe will result in more efficient or cost-effective regional transmission expansion, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which can enhance competition in wholesale electricity markets and facilitate access to lower-cost generation). In turn, we expect that these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1105. Additionally, as discussed further below, we disagree with commenters that question the necessity of this reform. In addition to our findings that this reform will help ensure just and reasonable rates, we find that the specific purpose of this reform—to require transmission providers to evaluate certain interconnection-related transmission needs—is not a requirement of any existing process. Additionally, we find that the qualifying criteria established by this reform will ensure that the reform avoids placing an onerous burden on transmission providers. Finally, we disagree that this reform is overly prescriptive; it does not dictate a specific result or require that transmission providers select a regional transmission facility to address identified interconnection-related transmission needs. This reform merely requires consideration of these interconnection-related transmission needs in the regional transmission planning process.

4. Commission Determination

1106. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning processes in their OATTs, consistent with the requirements in this final order, to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process, as more fully described below. We find that this requirement will ensure that more efficient or cost-effective transmission expansion can be effectuated through regional transmission planning processes and will eliminate a potential barrier to entry for new generation resources, thereby enhancing competition in wholesale electricity markets and facilitating access to lower-cost generation. As a result, this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1107. In this final order, we adopt the NOPR proposal with modification. First, we require transmission providers to evaluate for selection regional transmission facilities to address certain identified interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in Long-Term Regional Transmission Planning. Second, we modify the NOPR proposal to require that an interconnection-related network upgrade associated with identified interconnection-related transmission needs must satisfy *both* the minimum cost and voltage criteria proposed in the NOPR to qualify for evaluation for selection.

1108. In recent years, spending on interconnection-related network upgrades has increased dramatically, and the high cost of interconnection is increasing the rate at which generators withdraw from the interconnection queue.[2368] While interconnection customers may withdraw for multiple reasons, the record in this proceeding shows that, in recent years, the deciding factor in many cases of withdrawal has become the interconnection customer's cost responsibility for expensive interconnection-related network upgrades.[2369] Consequently, interconnection customers are unlikely to resolve these interconnection-related transmission needs through the generator interconnection process.

1109. Where interconnection-related transmission needs are repeatedly

[2366] The Commission has previously found that policies eliminating barriers to entry for generation resources can enhance competition in bulk power markets. *Standardization of Generator Interconnection Agreements & Procs.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at PP 694 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220 at P 579, *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007); Order No. 2023, 184 FERC ¶ 61,054 at P 44. Limited access to new and more competitive supplies of generation can increase the energy rates paid by wholesale customers. Order No. 2023, 184 FERC ¶ 61,054 at P 43.

[2367] *See, e.g.,* Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that ''[f]acilities beyond the Point of Interconnection [(*i.e.,* interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users'').

[2368] ACEG 2021 Interconnection Report at 17.

[2369] NOPR, 179 FERC ¶ 61,028 at P 162; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and Intermountain Initial Comments at 14.

identified but not constructed, the implication is that, despite the potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers, there are compelling reasons, such as proximity to fuel sources, why generators seek to locate a point of interconnection at a specific location or locations associated with transmission constraints. When interconnection customers that have invested time and resources in engaging in the generator interconnection process choose to withdraw rather than fund interconnection-related network upgrades, it becomes increasingly apparent that interconnection customer(s) are unlikely to resolve interconnection-related transmission needs through the generator interconnection process.

1110. At the same time, the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer.[2370] As a result, planning these types of upgrades to the transmission system in a piecemeal fashion, exclusively through the generator interconnection process, limits the development of transmission facilities that would provide benefits to the transmission system beyond those received by the interconnection customer. This is the case where interconnection-related network upgrades of substantial cost are repeatedly identified to address interconnection-related transmission needs, but those needs continue to go unresolved through the generator interconnection process. In such cases, it may be more efficient or cost-effective to address such needs through the regional transmission planning and cost allocation process. Therefore, reforms are necessary to require interconnection-related transmission needs associated with interconnection-related network upgrades that are repeatedly identified in the generator interconnection process to be evaluated through the regional transmission planning and cost allocation process. We believe that this approach will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation).[2371] As a result, these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1111. While we require transmission providers to evaluate regional transmission facilities that address certain interconnection-related transmission needs identified by this reform in the existing Order No. 1000 regional transmission planning and cost allocation processes, we allow for flexibility in how transmission providers evaluate such facilities for selection. Transmission providers may adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (*e.g.,* economic or reliability processes) to evaluate and potentially select these types of transmission facilities. By not requiring a specific process, we permit transmission providers to propose the best method to incorporate this requirement within their existing regional transmission planning processes. We also encourage transmission providers to consider, as part of the evaluation process, whether regional transmission facilities that address certain identified interconnection-related transmission needs may also address other regional transmission needs more efficiently or cost-effectively.

1112. Several commenters suggest alternative reforms to coordinate or consolidate regional transmission planning and generator interconnection processes or to modify existing cost allocation criteria.[2372] We find these requests to be outside the scope of this proceeding and lacking in record support to adequately consider whether to adopt them in this final order. In this final order, we are addressing the narrow issue of interconnection-related transmission needs being repeatedly identified yet continuing to go unresolved through the generator interconnection process, even though it may be more efficient and cost-effective to evaluate such needs through the regional transmission planning and cost allocation process.

1113. We find uncompelling general arguments from commenters that oppose the Commission's proposal because the reform addresses a deficiency in existing regional transmission planning and cost allocation processes, will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates, is not unduly burdensome, and does not dictate a particular outcome. The level of prescriptiveness of this reform strikes the right balance between an open-ended requirement, which might not address the need for reform, and a very prescriptive requirement that could be overly burdensome to transmission providers.

1114. We are unpersuaded by Ameren's argument that this reform will result in inefficient regional transmission planning because it will not minimize the total cost to end-use customers.[2373] As explained above, this reform will enable transmission providers to identify through regional transmission planning the more efficient or cost-effective transmission solution to address an interconnection-related transmission need.

1115. We clarify in response to Vistra that transmission providers must make the newly created interconnection capacity equally available to all interconnection and transmission customers consistent with the Commission's open access policy.[2374] Any interconnection customers whose interconnection requests related to the initial identification of the interconnection-related transmission need would not have any priority rights to that newly created interconnection or transmission capacity. Additionally, we clarify, in response to NRECA's request, that we are not requiring interconnection-related network upgrades associated with withdrawn interconnection requests to be given

[2370] *See, e.g., Entergy Svs., Inc.* v. *FERC,* 391 F.3d 1240, 1247–48 (2004); Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that ''[f]acilities beyond the Point of Interconnection [(*i.e.,* interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users''); *see also* ACORE ANOPR Comments, Ex. 5 at 4–7; CAISO ANOPR Comments at 53–54 (stating that in CAISO ''transmission facilities at 200 kV and above are eligible for regional cost allocation,'' including location-constrained resources interconnection facilities, because ''this voltage threshold . . . recognizes that high voltage transmission facilities support and provide benefits to all customers to the CAISO grid'').

[2371] While in this portion of the final order we discuss the requirement that transmission providers evaluate in their existing regional transmission planning and cost allocation processes regional transmission facilities that address certain interconnection-related needs, we also expect that many of the other reforms in this final order regarding Long-Term Regional Transmission Planning will address the difficulties generators face in interconnecting to the transmission system and the cost allocation mismatch described here, including required Factor Category Six, interconnection requests and withdrawals.

[2372] *E.g.,* Enel Initial Comments at 4–5.

[2373] Ameren Initial Comments at 18.

[2374] Vistra Initial Comments at 33–34.

preferential treatment in regional transmission planning.[2375]

1116. In response to commenters arguing that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs,[2376] we explain that we are not requiring transmission providers to evaluate regional transmission facilities that address interconnection-related transmission needs for every withdrawn interconnection request. Instead, this reform is focused only on certain interconnection-related transmission needs that meet the specific qualifying criteria detailed below. We do not assume that where these criteria are met, the relevant interconnection customers have necessarily withdrawn from the interconnection queue solely due to high interconnection-related network upgrade costs. Rather, we determine that these criteria only suggest that high costs were *likely* a factor prompting, or at least contributing to, the relevant withdrawals. We conclude that where the criteria are met, there may be an opportunity for a more efficient or cost-effective regional transmission solution, such that an evaluation of the relevant interconnection-related transmission need(s) is appropriate.

1117. We are not persuaded to reject this reform based on commenters' assertions that this reform will shift the costs of interconnection-related network upgrades from interconnection customers to load.[2377] This final order requires transmission providers to evaluate in their existing Order No. 1000 regional transmission planning and cost allocation processes regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process. Transmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply, and this final order does not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process. If a regional transmission facility that addresses identified interconnection-related transmission needs is not selected as part of the regional transmission planning process, then the associated regional cost allocation method would not apply; however, if the facility is selected, then the regional transmission planning process has determined that the regional transmission facility is a more efficient or cost-effective regional transmission solution. Additionally, if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits.

1118. In response to TAPS' request that the Commission clarify that regions may propose differing cost allocation methods for transmission facilities selected to address interconnection-related transmission needs versus transmission facilities selected to address other types of transmission needs,[2378] we clarify that the requirements adopted here merely create an obligation for transmission providers to evaluate regional transmission facilities that address certain identified interconnection-related transmission needs in the existing regional transmission planning and cost allocation processes. As such, to the extent that transmission providers wish to propose further changes to their Order No. 1000 regional transmission planning cost allocation method(s) because of this requirement, they would need to do so in separate FPA section 205 filings rather than on compliance with this final order.

1119. We disagree with commenters that the requirements adopted herein will incentivize gaming by interconnection customers to include interconnection-related network upgrades in the regional transmission planning process.[2379] We also disagree with commenters that claim that interconnection customers will submit spurious interconnection requests.[2380] Interconnection requests require significant financial commitments from the interconnection customer (*e.g.,* application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023,[2381] and therefore we find it unlikely that an interconnection customer would submit multiple interconnection requests (in multiple queue cycles) in order to trigger this requirement because of the possibility that transmission providers may eventually develop an interconnection-related network upgrade by selecting it in a regional transmission plan for purposes of cost allocation. An interconnection customer would face several risks in pursuing such a strategy, including the risk that the regional transmission solution for the interconnection-related transmission need is not selected, and the risk that the newly created interconnection or transmission capacity is allocated to a different transmission or interconnection customer. For these reasons, we decline to adopt Invenergy's request to modify the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.[2382]

1120. In response to Eversource's request that the Commission clarify that submitting and withdrawing interconnection requests with the intent of requiring transmission providers to evaluate the associated interconnection-related transmission needs in their regional transmission planning process is in violation of the Commission's regulations, including but not limited to the duty of candor and prohibition of market manipulation,[2383] as noted above, the generator interconnection process requires significant financial commitments for interconnection requests to enter and proceed in the queue, and many transmission providers have imposed additional readiness requirements to encourage early withdrawal of non-viable interconnection requests. For these reasons, we disagree with the gaming concerns raised by Eversource.[2384]

[2375] NRECA Reply Comments at 10–11.

[2376] CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

[2377] APPA Initial Comments at 31; Industrial Customers Initial Comments at 13; NRECA Initial Comments at 41–42 (citation omitted); NRECA Reply Comments at 8–9; PJM Initial Comments at 89–90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

[2378] TAPS Initial Comments at 13–14.

[2379] Ameren Initial Comments at 18–19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7–8; EEI Initial Comments at 18; Eversource Initial Comments at 23–24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12–13; Shell Initial Comments at 29–30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

[2380] Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33–34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

[2381] *See, e.g.,* Order No. 2023, 184 FERC ¶ 61,054 at P 502.

[2382] Invenergy Reply Comments at 14–15.

[2383] Eversource Initial Comments at 23–24 (citing 18 CFR 35.41; 18 CFR 1c.2).

[2384] While we are not concerned about gaming here, to the extent that there is evidence of a false representation or gaming of the market rules, a referral to the Office of Enforcement may be

1121. We also grant SEIA's request to clarify that the phrase ''interconnection-related transmission needs'' allows transmission providers to identify individual regional transmission solutions to address each identified interconnection-related transmission need, or an aggregate regional transmission solution to address multiple interconnection-related transmission needs. In response to commenters arguing that the reforms issued under Order No. 2023 will address interconnection-related issues more appropriately than the NOPR proposal,[2385] we explain that the reforms in this rulemaking are intended to address situations when interconnection-related network upgrades are repeatedly identified but not constructed and instances when regional transmission solutions to address the needs that would have been addressed by those interconnection-related network upgrades would provide widespread transmission benefits that extend beyond the interconnection customer, which are not addressed in Order No. 2023.

B. Transmission Planning Process Evaluation

1. NOPR Proposal

1122. In the NOPR, the Commission proposed to require the transmission providers in each transmission planning region to consider regional transmission facilities that address interconnection-related transmission needs pursuant to the proposed coordination reform through the Long-Term Regional Transmission Planning process proposed in the NOPR. Specifically, the Commission proposed to require that transmission providers in each transmission planning region incorporate the specific interconnection-related transmission needs identified through the coordination reform as a factor used to develop Long-Term Scenarios in the Long-Term Regional Transmission Planning proposed in the NOPR.[2386]

2. Comments

1123. Several commenters assert that the NOPR proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support interconnections.[2387] For example, Xcel argues that Long-Term Scenarios will be driven by the same factors that cause interconnection customers to make interconnection requests, such as optimal geographic locations for generation development.[2388] Similarly, EEI states that Long-Term Regional Transmission Planning, if properly implemented, already takes into account factors that support generator interconnection.[2389]

1124. Some of these commenters further claim that the Commission's coordination proposal's reliance on backward-looking interconnection needs would be less effective than planning on future system interconnection needs. CAISO argues that the Commission's proposal is backward-looking and therefore will not promote productive, forward-looking transmission planning.[2390] Vistra claims that an effective transmission planning process will identify interconnection needs and provide solutions within the context of a future system, rather than relying on prior interconnection studies addressing a specific generator interconnection request.[2391] Similarly, ISO/RTO Council recommends that the Commission direct transmission planners to consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis, rather than the coordination proposal's backwards-looking process.[2392]

1125. MISO states that because the generator interconnection process is designed to identify the minimum amount of interconnection-related network upgrades to interconnect new resources, Long-Term Regional Transmission Planning is the proper avenue to holistically evaluate system needs. MISO notes that it already has a mechanism in place to include interconnection-related network upgrades in its Long-Range Transmission Plan process if the interconnection-related network upgrade is found to have region-wide benefits.[2393]

3. Commission Determination

1126. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to evaluate regional transmission facilities that address certain interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes instead of in Long-Term Regional Transmission Planning. We find that this modification will better alleviate transmission limitations by providing a starting point for identifying and evaluating regional transmission solutions that are more efficient or cost-effective when analyzed in the near term.[2394] Specifically, requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes will allow such needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions. Evaluation of interconnection-related transmission needs in the existing Order No. 1000 regional transmission planning and cost allocation processes is most appropriate because such evaluation would occur at shorter intervals and would likely result in more expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.

1127. We agree with commenters that future interconnection-related transmission needs will be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios. Nonetheless, for the reasons described above, we find that current interconnection-related transmission needs can be considered more effectively through the nearer-term existing Order No. 1000 regional transmission planning and cost allocation processes. As such, we disagree with commenters that assert that the Commission's proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support generator interconnections.[2395] That said, we emphasize that, as transmission providers gain experience with Long-Term Regional Transmission Planning, we anticipate that they will identify

appropriate to determine whether a violation of the Commission's regulations has occurred.

[2385] Dominion Reply Comments at 8; Idaho Power Initial Comments at 6–7; Illinois Commission Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 15.

[2386] NOPR, 179 FERC ¶ 61,028 at P 167.

[2387] AEP Initial Comments at 19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8–9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

[2388] Xcel Initial Comments at 15.

[2389] EEI Initial Comments at 18.

[2390] CAISO Initial Comments at 6, 34–35.

[2391] Vistra Initial Comments at 33.

[2392] ISO/RTO Council Initial Comments at 9.

[2393] MISO Initial Comments at 44, 46–47; MISO Reply Comments at 29.

[2394] *See* NOPR, 179 FERC ¶ 61,028 at P 165.

[2395] AEP Initial Comments at 18–19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8–9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

fewer interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process because transmission providers will plan to address Long-Term Transmission Needs, including those driven by Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations that affect the future resource mix and demand; Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; Factor Category Six: generator interconnection requests and withdrawals, and Factory Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, through Long-Term Regional Transmission Planning.

1128. Some commenters, including Vistra and ISO/RTO Council, claim that the NOPR proposal to rely on needs identified in prior interconnection studies would be less effective at planning for interconnection-related transmission needs compared to more future-oriented approaches. We agree that an effective regional transmission planning process will identify interconnection-related transmission needs and evaluate regional transmission solutions to those needs within the context of a future system. We further agree that transmission providers should consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis. For these reasons, we require transmission providers to incorporate seven specific categories of factors in their development of Long-Term Scenarios used in Long-Term Regional Transmission Planning, including Factory Category Six: generator interconnection requests and withdrawals. However, we disagree that the coordination proposal should not rely on past results from the generator interconnection process or specific interconnection requests in determining what interconnection-related transmission needs should be evaluated in the existing Order No. 1000 regional transmission planning and cost allocation processes. Interconnection-related network upgrades repeatedly identified in past interconnection studies are strongly indicative that a location (despite presenting potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers) is otherwise valuable for location of new generation.

1129. Finally, because we are modifying the NOPR proposal to no longer apply to Long-Term Regional Transmission Planning, commenters' specific concerns that this proposal is duplicative to the categories of factors requirements in the development of Long-Term Scenarios are moot.

C. Qualifying Criteria

1. NOPR Proposal

1130. In the NOPR, the Commission proposed to require that transmission providers evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (beginning at the time of the withdrawal of the first underlying interconnection request); (2) the interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV and/or an estimated cost of at least $30 million; (3) those interconnection-related network upgrades have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the upgrade has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.[2396]

1131. The Commission proposed that the initial five-year time period begin five calendar years prior to the initial effective date of the Commission-accepted tariff provisions proposed to comply with this reform such that, upon the Commission's acceptance of such tariff provisions, the transmission provider would consider interconnection-related network upgrades identified to address the same interconnection-related transmission need in at least two interconnection queue cycles in the five calendar years prior to the effective date established in the order accepting those tariff revisions.[2397] The Commission also proposed to require that transmission providers in each transmission planning region consider whether the interconnection-related transmission need for which the transmission provider identified the interconnection-related network upgrade is the same in multiple interconnection queue cycles.[2398] That is, if an interconnection-related transmission need is driving the identification of an interconnection-related network upgrade on the transmission system in one interconnection queue cycle and an interconnection-related network upgrade with, for example, a different voltage, starting point, or ending point is identified in the next interconnection queue cycle to address the same interconnection-related transmission need, then the first criterion of the proposed coordination reform would be satisfied.[2399] The Commission stated that it believes that this approach will appropriately account for differences in technology, study assumptions, system topology, and/or interconnection requests that may occur over time that may result in different interconnection-related network upgrades to address the same interconnection-related need.[2400]

1132. The Commission stated that it believes that the proposed criteria the transmission provider must use to identify the interconnection-related transmission needs that should be considered in the regional transmission planning process will help to ensure that the associated interconnection-related network upgrades are likely to have produced benefits beyond those provided to the interconnection customers whose interconnection requests the interconnection-related network upgrades are needed to accommodate.[2401]

1133. To avoid shifting costs inappropriately from generators in the generator interconnection process to transmission customers through the regional transmission planning process, the Commission further proposed to limit the scope of interconnection-related transmission needs to be considered in the regional transmission planning process to those interconnection-related transmission needs not addressed by interconnection-related network upgrades memorialized in an executed generator

[2396] NOPR, 179 FERC ¶ 61,028 at P 166.

[2397] *Id.* P 170.

[2398] *Id.* P 171.

[2399] *Id.*

[2400] *Id.*

[2401] *Id.* P 168.

interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission).[2402]

2. Comments

1134. Multiple commenters generally support the NOPR proposal but express concerns about the eligibility criteria proposed in the NOPR and request modification.[2403] SDG&E states that the criteria defined in the NOPR strike an appropriate balance to cover many situations in which generation is needed, while also protecting ratepayers from unnecessary costs.[2404]

1135. Avangrid argues that, while the NOPR proposal has merit, the Commission should allow transmission providers to determine the most appropriate thresholds.[2405] SEIA asks the Commission to allow each transmission planning region to determine its own threshold, which may include lower voltage lines and substations.[2406] Indicated PJM TOs further argue that the proposed criteria may not be appropriate in all transmission planning regions.[2407]

1136. MISO argues that transmission planning regions should be able to develop their own cost and voltage criteria. MISO explains that it may be difficult to implement the requirement that interconnection-related network upgrades that qualify must ''not currently be planned to be developed'' in the interconnection process because in MISO's experience interconnection-related network upgrades shift from queue cycle to queue cycle as withdrawals occur, and as a result MISO suggests deleting this requirement. MISO opposes the requirement to identify any interconnection-related network upgrade that is identified in multiple generator interconnection studies as it would require the review and comparison of numerous studies to comply with no increased benefit.[2408]

1137. Multiple commenters that generally support the NOPR proposal suggest modification to the NOPR's proposed cost and voltage eligibility criteria. Pattern Energy suggests that the Commission should allow consideration of interconnection-related network upgrades that would meet either a voltage or a cost threshold because, for example, lower voltage lines that cost more than $30 million can often satisfy an interconnection need.[2409] Pattern Energy and Pine Gate argue that the Commission should lower the voltage threshold to 100 kV.[2410] Shell asks the Commission to lower the 200 kV threshold to 115 kV or to remove it entirely in favor of a cost threshold that is updated regularly based on inflation or some other Commission-approved indicator.[2411]

1138. Pine Gate argues that the Commission should reduce the cost threshold to $10 million.[2412] SEIA argues that the cost threshold should be replaced with a $100,000/MW threshold.[2413] US DOE argues that a $30 million cost threshold may not be appropriate because some interconnection-related network upgrades that meet this eligibility factor may only benefit a limited number of interconnection customers. As an alternative, US DOE adds that the Commission should consider interconnection-related network upgrades ''that would provide benefits beyond the local interconnection level or that would improve interconnection efficiencies across a wider geographic area and not substations, voltage support devices, or other local connection upgrades.''[2414]

1139. Dominion states that the relatively low voltage and cost thresholds in the Commission's proposal invites interconnection customers to seek bigger investments than needed or select a location that increases the cost of interconnection.[2415] Dominion further argues that the number, size, or frequency of interconnection requests should not be used as a basis for planning transmission projects, because the process could be subject to gaming, where speculative interconnection requests could result in transmission buildouts and spending that are not justified by actual grid needs or economics.[2416]

1140. Some commenters take issue with the NOPR's proposed criteria. Indicated PJM TOs argue that there is no record evidence to support the proposed 200 kV and $30 million cost threshold criteria.[2417] PJM states that few interconnection studies have identified the need for interconnection-related network upgrades in excess of $30 million.[2418] Illinois Commission contends that many projects in the interconnection queue are associated with interconnection-related network upgrades that meet the repeatedly-identified and 200 kV thresholds and that simply folding interconnection costs into transmission planning may expedite the queue at the expense of efficiency and cost-effectiveness.[2419] Indicated PJM TOs argue that limiting consideration to only generating facilities that have not yet signed (or had filed) an interconnection agreement will result in studying only uneconomic projects, which would run afoul of the cost causation principle.[2420]

1141. Interwest argues that the Commission should not require the identification of the interconnection-related network upgrade in two queue cycles over the five-year lookback period because such a requirement would limit the number of identified interconnection-related network upgrades that would trigger this newly proposed process.[2421] Pine Gate states that the Commission's look-back period should be at least the two immediately preceding interconnection queue cycles, or, where serial studies have been performed, during the preceding five years beginning at the time of the withdrawal of the first underlying interconnection request.[2422] Pine Gate argues that this revision will ensure that study results will be available for use in identifying interconnection-related network upgrades to evaluate.[2423] SEIA argues that once a transmission provider identifies the same interconnection-related network upgrade in two interconnection cycles, that line should be included in the next Long-Term Regional Transmission Planning update cycle even if five years have not passed since initial identification.[2424] Pattern Energy supports SEIA's requests.[2425]

1142. EEI and Eversource are unsure of the stage of the generator interconnection process at which a project would meet the proposed criteria.[2426] Eversource requests that the

[2402] *Id.* P 173.

[2403] NARUC Initial Comments at 19–20; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments 31–33; SEIA Initial Comments at 14–15; Shell Initial Comments at 30; TAPS Initial Comments at 13; US DOE Initial Comments at 28.

[2404] SDG&E Initial Comments at 3.

[2405] Avangrid Initial Comments at 12.

[2406] SEIA Initial Comments at 15.

[2407] Indicated PJM TOs Initial Comments at 15–16.

[2408] MISO Initial Comments at 45–46.

[2409] Pattern Energy Initial Comments at 28.

[2410] Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32.

[2411] Shell Initial Comments at 30.

[2412] Pine Gate Initial Comments at 32.

[2413] SEIA Initial Comments at 15.

[2414] US DOE Initial Comments at 28.

[2415] Dominion Initial Comments at 32.

[2416] Dominion Reply Comments at 7–8.

[2417] Indicated PJM TOs Initial Comments at 15.

[2418] PJM Initial Comments at 88.

[2419] Illinois Commission Initial Comments at 8–9.

[2420] Indicated PJM TOs Initial Comments at 16.

[2421] Interwest Initial Comments at 3, 11.

[2422] Pine Gate Initial Comments at 31.

[2423] *Id.*

[2424] SEIA Initial Comments at 15.

[2425] Pattern Energy Reply Comments at 10–11.

[2426] EEI Initial Comments at 17–18; Eversource Initial Comments at 24.

Commission require transmission providers to specify the stage in the interconnection process that an interconnection-related network upgrade is identified.[2427]

1143. Pine Gate asks the Commission to combine the third and fourth criteria into one criterion: those interconnection-related network upgrades that are not developed or in development and not currently committed to be built under an interconnection service agreement or any related construction agreement.[2428]

1144. Some commenters argue that the Commission's proposed criteria create too simplistic of a method for determining which interconnection-related network upgrades should be evaluated in Long-Term Regional Transmission Planning.[2429] Pennsylvania Commission argues that, without a rigorous examination of why an interconnection application failed, there is no proof that there exists a need for building interconnection-related network upgrades as part of Long-Term Regional Transmission Planning.[2430] NARUC argues that the meaning of the term ''multiple times'' should be informed by a process that also examines the reasons why the previous interconnection requests were withdrawn, including generation developer land acquisition decisions or the identification of more economic transmission design alternatives.[2431] Vistra takes issue with the fact that the Commission does not distinguish between situations when developers simply sought to develop in an uneconomic area versus when a more efficient or cost-effective transmission project would have been identified as part of the regional transmission planning process.[2432]

3. Commission Determination

1145. We adopt the NOPR proposal, with modification, to require that, for a regional transmission facility to address an interconnection-related transmission need to qualify for evaluation through the regional transmission planning process for selection under this reform, any interconnection-related network upgrade identified to meet that interconnection-related transmission need must meet both the proposed voltage *and* cost criteria. Thus, we require transmission providers to evaluate for selection in their existing Order No 1000 regional transmission planning processes regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions); (2) an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million; (3) such interconnection-related network upgrade(s) have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the network upgrade(s) has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.

1146. We find it necessary to establish these criteria to limit the scope of the requirement for transmission providers to evaluate regional transmission facilities to address interconnection-related transmission needs in their regional transmission planning processes to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. We find that each of the four criteria are necessary to identify the appropriate set of interconnection-related transmission needs. Moreover, we find that the modification to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need must satisfy both the voltage and cost thresholds better limits the scope of this reform by ensuring that any regional transmission facilities evaluated to address such interconnection-related transmission needs are more likely to provide widespread benefits to transmission customers.[2433]

1147. We further find that these criteria strike a reasonable balance between precision and workability. Our reforms here are intended to ensure that transmission providers must identify interconnection-related transmission needs for evaluation in their regional transmission planning processes that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Requiring in-depth qualitative analysis of individual interconnection requests, including consideration of why they were withdrawn, as some commenters suggest, would undermine these goals. Furthermore, these criteria simply determine whether transmission providers must *evaluate* regional transmission facilities to address any given interconnection-related transmission need for potential selection; transmission providers may still separately assess whether any particular regional transmission facility qualifies for selection in the relevant existing regional transmission planning process(es). Therefore, we disagree with commenters that argue that the proposed criteria create too simplistic a method for determining which interconnection-related transmission needs should be evaluated in regional

[2427] Eversource Initial Comments at 24.

[2428] Pine Gate Initial Comments at 32–33.

[2429] NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2430] Pennsylvania Commission Initial Comments at 8.

[2431] NARUC Initial Comments at 19.

[2432] Vistra Initial Comments at 20.

[2433] The Commission has previously found that network upgrades can benefit all transmission customers. *See* Order No. 2003, 104 FERC ¶ 61,103 at PP 21, 65 (stating ''[m]ost improvements to the Transmission System, including Network Upgrades, benefit all transmission customers'' and ''the definition of Network Upgrade [includes] the phrase 'at or beyond the Point of Interconnection,' . . . [f]acilities beyond the Point of Interconnection are part of the Transmission Provider's Transmission System and benefit all users''); Order No. 2003–A, 106 FERC ¶ 61,220 at P 584 (citing *Entergy Servs., Inc.* v. *FERC,* 319 F.3d 536, 543–544 (D.C. Cir. 2003)). The Commission has also previously found, and the record demonstrates, that higher-voltage transmission facilities are more likely to provide widespread benefits to transmission customers. *See* NOPR, 179 FERC ¶ 61,028 at PP 32 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486), 168; *Sw. Power Pool, Inc.,* 131 FERC ¶ 61,252, at P 73 (2010); *Midwest Indep. Trans. Sys. Operator, Inc.,* 129 FERC ¶ 61,060, at P 8 (2009). *See also, e.g.,* CAISO ANOPR Comments at 54; Invenergy Initial Comments at 14; Southeast PIOs Initial Comments at 24.

transmission planning and cost allocation processes.[2434]

1148. We decline to allow transmission providers to determine appropriate qualifying criteria,[2435] because the record supports our adoption of the qualifying criteria established by this order. As described directly above, we find that these specific criteria ensure that the interconnection-related transmission needs that we require transmission providers to evaluate through their regional transmission planning processes are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Furthermore, transmission providers retain the flexibility to determine whether to select a regional transmission facility, and these criteria will simply determine whether transmission providers, pursuant to this final order, must evaluate interconnection-related transmission needs in the Order No. 1000 regional transmission planning and cost allocation processes.

1149. We also disagree with Indicated PJM TOs' argument that the proposed criteria may not be appropriate in all transmission planning regions because of the differences in scales, topology, and economics.[2436] While each transmission planning region is unique, we find that the criteria that we establish here are broad enough to capture interconnection-related network upgrades that are likely to produce benefits beyond the interconnection customer across transmission planning regions despite their differences. Furthermore, as stated above, transmission providers in each transmission planning region retain the flexibility to select regional transmission facilities, and the criteria that we adopt here do not mandate that the transmission providers in any transmission planning region select any particular regional transmission facilities to address interconnection-related transmission needs.

1150. Additionally, we find that the qualifying criteria that we establish here that an interconnection-related need must be repeated twice and meet both voltage and cost thresholds are just and reasonable. We disagree with commenters that argue for the adoption of different criteria or for the elimination of one or both criteria.[2437] We find that the purpose of the criteria established here is precisely to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration in the existing Order No. 1000 regional transmission planning and cost allocation processes. The requirement of the repeat identification of an interconnection-related need in at least two interconnection queue cycles during the preceding five years criterion provides an important limit on the extent to which evaluation is required. Namely, this and the other criteria together indicate that it is likely that the relevant interconnection-related transmission needs will persist but were not resolved because the high associated interconnection-related network upgrade costs drove the withdrawal of the underlying interconnection requests. The repeat identification of interconnection-related network upgrades driven by a common interconnection-related transmission need also indicates that the constraint that the interconnection-related network upgrades were identified to address is not unique to a single interconnection request at a single point in time. Additionally, relaxing this repeat identification requirement may be overburdensome to transmission providers because it could increase the number of interconnection-related transmission needs that transmission providers must evaluate in their regional transmission planning and cost allocation processes.

1151. We find that it is necessary to establish a cost threshold criterion that is stringent enough to capture those interconnection-related network upgrades that are likely to have caused the underlying interconnection requests to withdraw. Additionally, we find that it is necessary to establish a voltage criterion that is high enough so that any regional transmission facility evaluated to address the underlying interconnection-related transmission need(s) is likely to produce benefits that extend beyond the interconnection customer. We further believe that these criteria are important to limit the number of interconnection-related transmission needs that transmission providers must evaluate to a practical set so that transmission providers do not have to evaluate numerous regional transmission facilities to address those needs that are unlikely to be selected.

1152. Consequently, the modification adopted here to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfies both the voltage and cost criteria will achieve these results. In particular, this modification will prevent transmission providers from evaluating interconnection-related transmission needs associated with interconnection-related network upgrades that are either above 200 kV but lower-cost or cost more than $30 million but are less than 200 kV, which means that they are less likely to provide more widespread benefits to transmission customers.

1153. The change to the voltage and cost criteria also address commenters' concerns.[2438] For example, as US DOE notes, in some instances, network upgrades that cost $30 million or more may only benefit a limited number of interconnection customers.[2439] Consequently, the change that we adopt to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfy both the voltage and cost criteria will more narrowly define a set of interconnection-related transmission needs that the transmission provider must evaluate in the regional transmission planning process.

1154. The record supports a 200 kV threshold. For example, as noted in the NOPR, the Commission has previously found CAISO's use of a 200 kV threshold was just and reasonable for determining eligibility for evaluating interconnection-related network upgrades in the regional transmission planning process. The Commission found that CAISO's proposed threshold ''strikes a reasonable balance between . . . accommodating the generators' need to interconnect . . . in a timely manner, and the benefits that can flow from evaluating the larger projects in the comprehensive transmission planning process.'' [2440] As such, we continue to believe that a 200 kV voltage threshold is sufficiently high such that the interconnection-related network upgrades can more reasonably be expected to produce regional benefits to

[2434] *See* NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

[2435] *See* Avangrid Initial Comments at 12; MISO Initial Comments at 45–46; SEIA Initial Comments at 15.

[2436] *See* Indicated PJM TOs Initial Comments at 15–16.

[2437] *See* Dominion Initial Comments at 32; Indicated PJM TOs Initial Comments at 15; Interwest Initial Comments at 3, 11; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; Shell Initial Comments at 30.

[2438] Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; US DOE Initial Comments at 28.

[2439] US DOE Initial Comments at 28.

[2440] *Cal Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,224, at P 103 (2010); *see also* NOPR, 179 FERC ¶ 61,028 at P 165 n.300 & P 172 n.302.

transmission customers than lower-voltage transmission facilities.

1155. We also continue to believe that $30 million is an appropriate threshold for the cost criteria related to this requirement. We find that the $30 million threshold is consistent with the record established in this proceeding regarding how the costs of interconnection-related network upgrades lead to interconnection customers withdrawing from the queue.[2441] A lower cost criterion may require transmission providers to evaluate in the regional transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades that have a greater likelihood to be affordable for interconnection customers. Additionally, we are concerned that the $/kW cost threshold proposed by SEIA may not capture interconnection-related network upgrades that are more likely to provide regional benefits to transmission customers beyond the interconnection customer. Further, transmission providers may face practical challenges in identifying the specific kW size corresponding to the interconnection-related transmission need associated with an interconnection-related network upgrade because the same interconnection-related network upgrade can be identified as needed for multiple interconnection requests (or groups of requests) of different kW sizes.

1156. Additionally, we reiterate that the criteria adopted herein do not require transmission providers to select any particular regional transmission facility to address interconnection-related transmission needs. Instead, we require transmission providers to simply evaluate regional transmission facilities to address interconnection-related transmission needs that meet these criteria for potential selection, recognizing that transmission providers may ultimately determine through their regional transmission planning processes that such regional transmission facilities are not eligible or sufficiently beneficial to be selected.

1157. We disagree with Indicated PJM TOs' argument that limiting evaluation to exclude interconnection-related network upgrades identified in generator interconnection requests that have executed (or requested to be filed unexecuted) an interconnection agreement will result in studying only uneconomic projects.[2442] This criterion ensures that transmission providers are not required to evaluate in their regional transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades for which an interconnection customer has already agreed to pay.[2443] Furthermore, in response to MISO's suggestion to delete this limiting aspect, we clarify that this criterion excludes instances in which an interconnection-related network upgrade is identified in an executed generator interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission),[2444] not instances where an interconnection-related network upgrade that meets the criteria in this section is identified as needed for an interconnection request that has not proceeded to the generator interconnection agreement phase of the interconnection study process.

1158. The criterion requiring that interconnection-related transmission needs are identified in at least two interconnection queue cycles during the preceding five years will help to ensure that an interconnection-related transmission need is likely to persist and is not unique to a single interconnection request before requiring transmission providers to evaluate a regional transmission facility to address that need for potential selection.[2445] We recognize that, in limited circumstances, it is possible that there may be only one interconnection queue cycle during a five-year period. We clarify that if more than five years pass between interconnection queue cycles, then this criterion should be read to include the interconnection queue cycle that immediately preceded the current interconnection queue where the interconnection-related transmission need is identified.[2446]

1159. We adopt the NOPR proposal that the initial five-year period will begin five calendar years prior to the effective date of the Commission-accepted tariff provisions proposed to comply with this final order. Thus, transmission providers must evaluate an interconnection-related transmission need that has been previously identified multiple times within the five years prior to the effective date of the Commission-accepted tariff provisions, but never been resolved due to the withdrawal of the underlying interconnection request(s). This assumes that the other qualifying criteria are met for the interconnection-related transmission need. The evaluation for selection of regional transmission facilities that address certain identified interconnection-related transmission needs must occur in the first Order No. 1000 regional transmission planning and cost allocation processes cycle that commences after the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions.

1160. Additionally, we clarify that if there are no queue cycles in the preceding five-year period because the transmission provider uses a first-come, first-served serial interconnection process, then this criterion will be met based on the identification of interconnection-related transmission needs in individual interconnection studies. That is, if the interconnection-related transmission need is identified in at least two individual interconnection studies during the preceding five-year period for interconnection customers that subsequently withdrew from the interconnection queue, then this criterion is met. We further clarify, as discussed immediately above, that if a transmission provider identifies the same interconnection-related transmission need in two interconnection queue cycles during a five-year period or less, the transmission provider must evaluate that interconnection-related transmission need even if five years have not yet passed since the initial identification.[2447]

1161. In response to Eversource's request that we require transmission providers to specify the stage in the generator interconnection process that an interconnection-related network upgrade is identified,[2448] we clarify that the criterion discussed herein applies no matter the stage in which the upgrades are identified, because we are concerned with interconnection-related transmission needs going unaddressed due to withdrawals regardless of the stage of the generator interconnection process.

1162. Finally, we decline to combine the third and fourth criteria into one criterion as Pine Gate suggests, because we find that it is unnecessary.[2449] This reform creates a process for the evaluation of interconnection-related

[2441] NOPR, 179 FERC ¶ 61,028 at P 172 n.303.

[2442] Indicated PJM TOs Initial Comments at 16.

[2443] NOPR, 179 FERC ¶ 61,028 at P 173.

[2444] MISO Initial Comments at 46.

[2445] Pattern Energy Reply Comments at 10–11; Pine Gate Initial Comments at 31; SEIA Initial Comments at 14–15.

[2446] *See* Pine Gate Initial Comments at 31.

[2447] *See* Pattern Energy Reply Comments at 10–11; SEIA Initial Comments 15.

[2448] *See* EEI Initial Comments at 17–18; Eversource Initial Comments at 24.

[2449] *See* Pine Gate Initial Comments at 32–33.

transmission needs in regional transmission planning and cost allocation processes if those needs have not been addressed and are unlikely to be addressed through the development of an interconnection-related network upgrade in the generator interconnection process. The purpose of the third criterion is to limit the reform to those interconnection-related transmission needs where the associated interconnection requests have been withdrawn; that is, this criterion requires the repeat withdrawal. The fourth criterion, that the interconnection-related network upgrade not be identified in a generator interconnection agreement, ensures that the interconnection-related network upgrade has not been developed and is not planned to be developed because a generator interconnection agreement memorializes the transmission owner's obligation to develop an identified interconnection-related network upgrade.[2450]

V. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

A. General Proposal

1. NOPR Proposal

1163. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to consider two specific technologies more fully in regional transmission planning and cost allocation processes: dynamic line ratings and advanced power flow control devices. The Commission recognized that selecting transmission facilities that incorporate such technologies serving a transmission function in the regional transmission plan for purposes of cost allocation could be more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies.[2451]

1164. More specifically, the Commission proposed to require transmission providers in each transmission planning region to consider for each identified regional transmission need whether selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices would be more efficient or cost-effective than selecting transmission facilities that do not incorporate these technologies. The Commission proposed that such consideration should first address whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other transmission facilities that are being considered for potential selection. Second, the Commission proposed that, when evaluating transmission facilities for potential selection, transmission providers in each transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective than potential regional transmission facilities that do not incorporate such technologies. The Commission proposed to apply this requirement in all aspects of the regional transmission planning processes, including the existing regional transmission planning process for near-term regional transmission needs and Long-Term Regional Transmission Planning. As is the case for any other transmission facility selected, the Commission proposed that the costs to incorporate dynamic line ratings or advanced power flow control devices selected, whether as an addition to an existing transmission facility or as part of a new regional transmission facility, be allocated using the applicable regional cost allocation method.[2452]

1165. The Commission noted that, as required by Order No. 1000, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected.[2453] The Commission proposed to extend this requirement such that transmission providers must ensure that the determination of whether to incorporate dynamic line ratings and advanced power flow control devices is sufficiently detailed for stakeholders to understand why they were or were not incorporated into selected regional transmission facilities.[2454]

1166. The Commission also sought comment on whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if dynamic line ratings are identified as a more efficient or cost-effective transmission facility.[2455]

2. Comments on General Proposal

1167. Many commenters, including technology developers, environmental advocates, ratepayer advocates, and independent market monitors, support the NOPR proposal.[2456] For example, many commenters state that these technologies provide significant annual cost savings [2457] or affect both the capital investment and consumer benefits of cost allocation.[2458] Additionally, some Federal legislators support the NOPR proposal.[2459] CARE

[2450] *See Pro forma* LGIA art. 11.3 (''Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades . . . described in Appendix B.'').

[2451] NOPR, 179 FERC ¶ 61,028 at PP 272–273.

[2452] *Id.* P 274.

[2453] *Id.* P 275 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328; Order No. 1000–A, 139 FERC ¶ 61,132 at P 267).

[2454] *Id.*

[2455] *Id.* P 277.

[2456] ACEG Initial Comments at 31; ACORE Initial Comments at 15–16; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 4; AEE Initial Comments at 27–28; CARE Coalition Initial Comments at 2–3; Certain TDUs Reply Comments at 7–9; Clean Energy Associations Initial Comments at 28; Clean Energy Associations Reply Comments at 7–8; Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36; DC and MD Offices of People's Counsel Reply Comments at 8–9; Evergreen Action Initial Comments at 4; Hannon Armstrong Reply Comments at 2; Illinois Commission Initial Comments at 11–13; Indicated US Senators and Representatives Initial Comments at 2; Joint Consumer Advocates Initial Comments at 13; Massachusetts Attorney General Initial Comments at 16–18; Michigan Conservative Energy Forum Supplemental Comments at 1; Michigan State Entities Initial Comments at 10; NARUC Initial Comments at 35; NASEO Initial Comments at 6; NASUCA Initial Comments at 7–8; NESCOE Initial Comments at 53; Nevada Commission Initial Comments at 13; Ohio Conservative Energy Forum Supplemental Comments at 1; Pennsylvania Commission Initial Comments at 11; PIOs Initial Comments at 22; PJM Market Monitor Initial Comments at 6; Potomac Economics Initial Comments at 5; Prysmian Initial Comments at 1; Smart Wires Initial Comments at 1; SPP Market Monitor Initial Comments at 9; US DOE Initial Comments at 36–37; WATT Coalition Initial Comments at 2; WATT Coalition Supplemental Comments at 2–3; Western Way Colorado Supplemental Comments at 1–2; Western Way Nevada Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[2457] Cross Sector Representatives Supplemental Comments at 1; WATT Coalition Supplemental Comments at 2–3.

[2458] Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum at 1; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[2459] Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 3.

Coalition asserts that the Commission should use all available tools and technologies to increase the efficiency and capacity of the transmission network.[2460] ELCON states that transmission planning processes should ascertain whether current infrastructure can be improved before reviewing costlier or slower options like greenfield transmission, and greater weight should be given to those transmission projects that incorporate grid enhancing technologies.[2461] Certain TDUs state that they participate actively in the MISO transmission planning process, and that they have observed that grid enhancing technologies and other non-transmission alternatives do not receive the attention that they deserve.[2462] AEE contends that the Commission has an obligation to promote the adoption of alternative transmission technologies, as directed by Congress in the Energy Policy Act of 2005, and AEE states that the Commission has not made explicit efforts to implement this mandate beyond offering rate incentives for alternative transmission technologies.[2463]

1168. Industrial Customers assert that requiring dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies will require transmission utilities to deploy capital where it is needed most to maintain reliability, which will reduce transmission costs to consumers because dynamic line ratings extend the useful life of existing transmission infrastructure and optimize existing grid capabilities.[2464] ENGIE claims that deploying grid enhancing technologies could help to contain costs and support efficient, advanced projects.[2465] Invenergy argues that, even if there may be instances where dynamic line ratings and advanced power flow control devices do not provide the best option with respect to cost, transmission providers should still undertake the analysis.[2466] Potomac Economics observes that incorporating grid enhancing technologies in the transmission planning process will help ensure that transmission owners do not incur inefficient transmission upgrade costs to mitigate congestion that can be reduced more cost-effectively by grid enhancing technologies.[2467]

1169. Individual state governmental entities as well as NASEO, NASUCA, and NESCOE emphasize the importance of considering more efficient or cost-effective alternatives.[2468] Some state commissions and US DOE cite the benefits of cost containment for customers.[2469] DC and MD Offices of People's Counsel and Clean Energy Associations assert that grid enhancing technologies provide value beyond lowering transmission costs, as they can be deployed quickly, are modular, have low environmental and geographic footprints, and can be developed at low risk.[2470] NARUC asserts that an effective transmission planning process should maximize the use of existing transmission and allow for building new transmission only where necessary or economic.[2471] Indicated US Senators and Representatives support the use of advanced transmission technologies to increase the efficiency and resilience of the electric grid.[2472]

1170. Many commenters support the consideration of alternative transmission technologies in transmission planning. For example, Certain TDUs argue that the Commission must protect ratepayers and consider all alternatives to ensure safe, reliable, and cost-effective transmission solutions, including the use of alternative transmission technologies.[2473] Invenergy avers that there may be instances where better using these technologies may require certain foundational investments (*e.g.,* appropriate software), but that only reinforces the need to establish a requirement to drive change.[2474] Industrial Customers state that transmission providers should have to consider grid enhancing technologies whenever additional transmission investment is the alternative because the cost of installing them will almost always be nominal compared to the benefits of reduced congestion, lower energy and capacity costs, and reduced need for increases in transmission system capability.[2475]

1171. WATT Coalition asserts that alternative transmission technologies and new transmission capacity are complementary.[2476] WATT Coalition and Industrial Customers further assert that there is substantial value in considering dynamic line ratings in Long-Term Regional Transmission Planning because they can provide data to strengthen assumptions made in the planning process.[2477] Specifically, WATT Coalition explains that historical data sets of dynamic transmission line ratings can be analyzed to create probabilistic line ratings on a seasonal, monthly, or more granular level to inform the transmission planning process, helping to maximize its efficiency.[2478] Finally, WATT Coalition states that the use of forecasted ambient-adjusted ratings (Ambient Adjusted Ratings) demonstrates that more granular data inputs can and should be captured to increase the value of new transmission investment, as well as increased reliability and market efficiency.[2479]

1172. Invenergy states that, if there are concerns about the burden associated with evaluating alternative transmission technologies, the Commission could adopt a reasonable threshold under which transmission providers are required to consider whether dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies may be more efficient or cost-effective. For example, Invenergy suggests that, if an overload is identified and the relevant facilities are overloaded by 20% or less, the transmission provider should be required to consider grid enhancing technologies as a solution. Invenergy urges the Commission to reject calls to make the proposal an optional process, noting that transmission providers can already consider these technologies, but many do not.[2480]

[2460] CARE Coalition Initial Comments at 3.

[2461] ELCON Initial Comments at 5, 20.

[2462] Certain TDUs Reply Comments at 8.

[2463] AEE Initial Comments at 29 (citing 42 U.S.C. 16422).

[2464] Industrial Customers Reply Comments at 13–14.

[2465] ENGIE Reply Comments at 3–4.

[2466] Invenergy Reply Comments at 17.

[2467] Potomac Economics Initial Comments at 5.

[2468] Massachusetts Attorney General Initial Comments at 16–18; Michigan State Entities Initial Comments at 10 (citing Institute for Policy Integrity ANOPR Reply Comments at 8); NASEO Initial Comments at 6; NASUCA Initial Comments at 7–8; NESCOE Initial Comments at 53.

[2469] Illinois Commission Initial Comments at 11–13; NARUC Initial Comments at 35–36; Nevada Commission Initial Comments at 13; Pennsylvania Commission Initial Comments at 11; US DOE Initial Comments at 36–37.

[2470] Clean Energy Associations Initial Comments at 27; DC and MD Offices of People's Counsel Reply Comments at 8.

[2471] Industrial Customers Reply Comments at 12; NARUC Initial Comments at 35.

[2472] Indicated US Senators and Representatives Initial Comments at 2.

[2473] Certain TDUs Reply Comments at 8.

[2474] Invenergy Reply Comments at 17.

[2475] Industrial Customers Reply Comments at 16.

[2476] WATT Coalition Reply Comments at 2.

[2477] Industrial Customers Reply Comments at 18; WATT Coalition Reply Comments at 1–3 (citing Appendix B of its Reply Comments).

[2478] WATT Coalition Reply Comments Appendix B at 12. For example, WATT Coalition reports that ERCOT uses historical dynamic line rating data in its regional transmission plan. *Id.* (citing ERCOT 2021 Regional Transmission Plan Report, section 1.2, *https://www.ercot.com/files/docs/2021/12/23/2021_Regional_Transmission_Plan_Report_Public.zip).*

[2479] *Id.* Appendix B at 13.

[2480] Invenergy Reply Comments at 16–17.

1173. Some commenters express partial support for the NOPR proposal but raise concerns about certain aspects.[2481] California Water supports consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning but recommends that any final order clarify that such technologies should be adopted only if they are considered in the regional transmission planning process as the Commission proposes, serve the purpose of cost containment, and are found to be efficient and cost-effective.[2482] TAPS states that while it supports the implementation of grid enhancing technologies, they may be better suited for consideration on a shorter regional transmission planning horizon.[2483] While Pattern Energy supports the consideration of grid enhancing technologies in Long-Term Regional Transmission Planning, it similarly notes that dynamic line ratings and advanced power flow control devices are shorter-term transmission solutions—helping to ''squeeze more'' out of the infrastructure that is operating or planned to be constructed.[2484]

1174. While ENGIE supports the Commission's proposal to require the evaluation and deployment of dynamic line ratings and advanced power flow control devices where beneficial in Long-Term Regional Transmission Planning, it notes that the operational data used by such devices are not yet easily incorporated into the transmission planning framework.[2485] Similarly, SEIA and Invenergy raise concerns that utilities struggle to consider, evaluate, and select these technologies as transmission solutions due to a lack of information about how they might be integrated into the transmission planning process.[2486]

1175. Finally, National Grid generally supports the notion that transmission providers should consider whether and how alternative transmission technologies can be incorporated into transmission planning and states that such technologies, in certain instances, may offer a more efficient or cost-effective alternative to other regional transmission facilities.[2487] However, National Grid states that, if the Commission adopts in a final order the requirement to fully consider dynamic line ratings and advanced power flow control devices, it should explain how it expects RTOs/ISOs to implement the first step of the consideration process articulated in the NOPR, *i.e.,* that the alternative transmission technologies being incorporated into existing transmission facilities ''could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities.'' [2488] According to National Grid, such a requirement would exceed the RTO/ISO's authority as the independent administrator of the competitive solicitation process.[2489]

1176. Many commenters oppose the NOPR proposal.[2490] Some commenters warn the Commission of the potential reliability and operational impacts of the widespread use of dynamic line ratings and advanced power flow control devices.[2491] APPA asserts that transmission dynamic line ratings and advanced power flow control devices should not be required until the industry has further experience with Ambient-Adjusted Ratings deployment.[2492] Exelon asserts that transmission providers already consider grid enhancing technologies and notes that, in many instances, the selection and deployment of grid enhancing technologies are fundamentally incompatible with the competitive transmission requirements in Order No. 1000, particularly in the context of development of new transmission facilities, where grid enhancing technologies are unlikely to be the lower cost solution, and may be considerably more expensive than traditional transmission technologies.[2493]

1177. Some commenters argue that further support is needed to justify any mandate to consider alternative transmission technologies in transmission planning.[2494] Kansas Commission asserts that any new requirements should be based on a data-driven, robust analysis demonstrating ratepayer benefits; it also cautions against using such technologies as a short-term fix.[2495] ATC states that the Commission should develop a record of the costs, risks, and potential impacts of widespread implementation of dynamic line ratings before mandating further action.[2496]

1178. Some commenters raise concerns about the costs of alternative transmission technologies. Mississippi Commission argues that mandating the use of technologies without considering their cost is not just and reasonable.[2497] ATC asserts that the costs of implementing dynamic line ratings system wide would not be nominal.[2498] US Chamber of Commerce asserts that dynamic line ratings are not a way to obtain ''free'' transmission capacity because there are costs associated with monitoring the ratings.[2499]

1179. Other commenters argue that the Commission should favor flexibility and not mandate that dynamic line ratings and advanced power flow control devices be considered.[2500] Georgia Commission states that it is reasonable for the Commission to encourage, rather than require, consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning.[2501] LADWP suggests that instead of mandating consideration of specific technologies that become obsolete, the Commission

[2481] CAISO Initial Comments at 37–39, California Water Initial Comments at 20; ENGIE Initial Comments at 6; Invenergy Initial Comments at 14–16; Ohio Consumers Initial Comments at 32–33; Pattern Energy Initial Comments at 29; SEIA Initial Comments at 21–22; SPP Initial Comments at 25–26, TAPS Initial Comments at 4, 21–22.

[2482] California Water Initial Comments at 20.

[2483] TAPS Initial Comments at 4, 21–22.

[2484] Pattern Energy Initial Comments at 29.

[2485] ENGIE Initial Comments at 6.

[2486] Invenergy Initial Comments at 14–16; SEIA Initial Comments at 21–22.

[2487] National Grid Initial Comments at 21.

[2488] *Id.* at 23 (quoting NOPR, 179 FERC ¶ 61,028 at P 274).

[2489] *Id.*

[2490] AEP Initial Comments at 33; Ameren Initial Comments at 23–24; APPA Initial Comments at 37; ATC Initial Comments at 7–8; Avangrid Initial Comments at 31; DATA Initial Comments at 17; Dominion Initial Comments at 40; Duke Initial Comments at 29–32; EEI Initial Comments at 20–22; Entergy Initial Comments at 26–28; Eversource Initial Comments at 27–28; Exelon Initial Comments at 18–23; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; Indicated PJM TOs Initial Comments at 19–20; ITC Initial Comments at 26–28; ITC Reply Comments at 27; LADWP Initial Comments at 5; Large Public Power Initial Comments at 31–34; MISO TOs Initial Comments at 23–24; Mississippi Commission Reply Comments at 8; New York TOs Initial Comments at 22–23; NRECA Initial Comments at 52; NYISO Initial Comments at 45, 47; OMS Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15–16; PJM Initial Comments at 105–109; PPL Initial Comments at 22–23; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36–37; US Chamber of Commerce Initial Comments at 9.

[2491] Duke Initial Comments at 31–32; Entergy Initial Comments at 27–28; MISO Initial Comments at 59–60.

[2492] APPA Initial Comments at 5.

[2493] Exelon Initial Comments at 21.

[2494] ATC Reply Comments at 3; Kansas Commission Initial Comments at 19–20.

[2495] Kansas Commission Initial Comments at 19–20.

[2496] ATC Reply Comments at 3.

[2497] Mississippi Commission Reply Comments at 8.

[2498] ATC Reply Comments at 3 (citing Pattern Energy Initial Comments at 30; Pine Gate Initial Comments at 40–41).

[2499] US Chamber of Commerce Initial Comments at 9.

[2500] Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

[2501] Georgia Commission Initial Comments at 7.

should require transmission providers to use Good Utility Practice to identify and use technologies that maximize the use of transmission assets in order to minimize impacts to ratepayers and the public.[2502]

1180. Similarly, National Grid argues that the Commission should not favor the deployment of the two proposed technologies over more efficient or cost-effective transmission facilities, and that focusing on specific technologies is likely to stifle innovation and will not lead to the identification of the more efficient or cost-effective transmission facilities.[2503] ATC disagrees with commenters that state that utilities are reluctant to implement these technologies,[2504] noting that it advocates for and uses advanced power flow control devices and other advanced technologies on its system.[2505] However, ATC describes widespread dynamic line rating deployment as costly.[2506]

1181. Other commenters urge the Commission to complete its consideration of the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings[2507] and/or wait for transmission providers to comply with Order No. 881[2508] before implementing the NOPR proposal on dynamic line ratings.[2509] Large Public Power states that the Commission appears to sidestep the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings, especially the technical and cybersecurity-related concerns in that docket.[2510] MISO TOs state that imposing a mandate in this proceeding would complicate the issue.[2511] ATC argues that a more prudent course of action would be to gain experience with Ambient-Adjusted Ratings before moving on to consideration of the use of dynamic line ratings.[2512] ITC asserts that dynamic line ratings and advanced power flow control devices should be implemented on an operational basis through existing Commission proceedings addressing such technologies.[2513]

1182. Several commenters specifically support the NOPR proposal of requiring consideration of both: (1) whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other transmission facilities that are being considered for potential selection; and (2) whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective than those without incorporating such technologies.[2514] Ohio Consumers emphasize the importance of considering dynamic line ratings and advanced power flow control devices for both proposed and existing projects, noting that the goal of using these technologies is to lower overall costs of new transmission for consumers, and citing to a DOE study that found that these technologies can defer or reduce the need for significant investment in new infrastructure projects, and increase the use of renewables by maximizing the capacity of current infrastructure.[2515]

1183. Others oppose the consideration of alternative transmission technologies on new transmission facilities.[2516] CAISO contends that a requirement to consider whether to incorporate dynamic line ratings and advanced power flow control devices as part of every new regional transmission facility identified to meet a reliability need would create more work without yielding significant benefits because incorporating such measures would not alter the scope of the underlying transmission facilities that are necessary to meet the reliability need.[2517] LADWP states that identification of specific technologies in a rulemaking seems inappropriate and asserts a transmission line that is not yet built has no operating history, and it should therefore be at the discretion of the transmission planner to consider and implement dynamic line ratings, as it would slow down the design and construction of the transmission line.[2518] Exelon states that, particularly in the context of new transmission facilities, grid enhancing technologies are very unlikely to be the lower cost solution relative to traditional transmission technologies, and for many technologies, they should be expected to be considerably more expensive than traditional transmission technologies (notwithstanding any additional benefits they may offer).[2519]

1184. Clean Energy Associations, Industrial Customers, and WATT Coalition support the implementation of a requirement for non-RTO/ISO regions to update their energy management systems if dynamic line ratings are identified as a more efficient or cost-effective transmission facility selected.[2520] ELCON agrees, asserting that the Commission's requirement for dynamic line ratings and advanced power flow control devices should apply to all Commission-jurisdictional transmission utilities, regardless of whether they are RTOs/ISOs.[2521] WATT Coalition adds that all transmission providers should be required to upgrade their energy management systems and keep them consistent across all transmission providers to accommodate the latest technologies.[2522] WATT Coalition further states that advanced power flow control devices and topology optimization do not require modifications to existing energy management systems, but that the implementation of such technologies would benefit from the increased flexibility of dynamic line rating-enabled energy management systems.[2523]

1185. Pattern Energy states that energy management systems and other equipment will need upgrades to integrate readouts from the dynamic line ratings equipment to minimize operator intervention and enhance operational awareness. Pattern Energy

[2502] LADWP Initial Comments at 5.

[2503] National Grid Initial Comments at 22–23.

[2504] ATC Reply Comments at 2 (citing Invenergy Initial Comments at 15).

[2505] *Id.* (citing ATC Initial Comments at 7).

[2506] *Id.* at 3.

[2507] *Implementation of Dynamic Line Ratings,* 178 FERC ¶ 61,110 (2022).

[2508] *Managing Transmission Line Ratings,* Order No. 881, 177 FERC ¶ 61,179 (2021).

[2509] ATC Reply Comments at 4–5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32–33; MISO TOs Initial Comments at 23–24.

[2510] Large Public Power Initial Comments at 32.

[2511] MISO TOs Initial Comments at 23.

[2512] ATC Initial Comments at 10.

[2513] ITC Reply Comments at 27.

[2514] ACORE Initial Comments at 15; Clean Energy Associations Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 36; Industrial Customers Initial Comments at 32–34; Michigan State Entities Initial Comments at 11; NASEO Initial Comments at 6; Ohio Consumers Initial Comments at 34; State Agencies Initial Comments at 17–18.

[2515] Ohio Consumers Initial Comments at 32–34 (citing US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact* (Feb. 2022), *https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf*).

[2516] CAISO Initial Comments at 6; LADWP Initial Comments at 5.

[2517] CAISO Initial Comments at 6. CAISO, however, supports considering these technologies in connection with new transmission facilities intended to meet economic or public policy needs. *Id.*

[2518] LADWP Initial Comments at 5.

[2519] Exelon Initial Comments at 21–22.

[2520] Clean Energy Associations Initial Comments at 28; Industrial Customers Initial Comments at 32–33; Industrial Customers Reply Comments at 11; WATT Coalition Initial Comments at 7.

[2521] ELCON Initial Comments at 21.

[2522] WATT Coalition Initial Comments at 7.

[2523] *Id.*

surmises, however, that any upgrades necessitated by a final order in this proceeding may be nominal given that dynamic line ratings and advanced power flow control devices should already be readily integrated with upgrades to energy management systems needed to comply with Order No. 881.[2524]

1186. Some commenters suggest alternative approaches to incorporating alternative transmission technologies into the transmission system. Vistra asserts that the Commission should modify the NOPR proposal to require: (1) the long-term transmission planning evaluation to include a generation capacity expansion scenario that incorporates the potential for enhanced capability through new market services; (2) early input during the transmission planning cycle from independent market monitors and stakeholders on market improvements that could enhance grid operations; and (3) all solicitations for long-term solutions to equally consider non-transmissions solutions that may include generation, technology, or market design changes that could more efficiently or cost-effectively address a need that otherwise would require construction or modification of transmission facilities.[2525]

1187. Some commenters request that the Commission establish more prescriptive requirements regarding the evaluation of the alternative transmission technologies than those proposed in the NOPR. Invenergy asserts that the NOPR proposal should be expanded to include other technologies and require transmission providers to select alternative transmission technologies when they provide the most efficient option.[2526]

1188. WATT Coalition urges the Commission to include an operational planning timeframe for topology optimization, dynamic line ratings, and modular advanced power flow control devices, which can all be deployed quickly. WATT Coalition states that the Commission could require consideration of these technologies for the top 5 or 10 most costly or critical constraints on a quarterly basis.[2527] WATT Coalition states that market participants should be able to request the use of grid enhancing technologies, and receive an answer from the transmission provider within a defined period of time, to be evaluated against alternatives used by the transmission provider.[2528] WATT Coalition also asserts that grid enhancing technologies should be required in appropriate instances and encouraged through incentives because utilities have little incentive to deploy them under standard cost-of-service regulation,[2529] and after implementing this order, the Commission should develop transmission incentives to complement a congestion threshold requirement, driving other creative applications of grid enhancing technologies where they would create the most value to consumers.[2530]

1189. Some commenters request more requirements regarding evaluation and/or deployment of alternative transmission technologies to meet transmission needs. WATT Coalition states that there are certain transmission technologies that are faster to deploy than traditional lines and urges the Commission to require an annual review of the Long-Term Regional Transmission Planning process and establish a fast track process for solutions with a lead time of less than 12 months and a capital cost of less than $50 million.[2531] WATT Coalition further states that the requirement to consider dynamic line ratings and advanced power flow control devices should also apply in any case where transmission capacity is valuable but the costs of a new line are not justified.[2532]

1190. Smart Wires and WATT Coalition argue that the Commission should direct transmission providers to: (1) designate advanced power flow control devices as the default solution for projects requiring a series capacitor; (2) ''require evaluation of advanced power flow control devices for thermal overloads that fall within 50% of the line rating,'' which they argue is when such devices are often most economically advantageous; (3) require evaluation of advanced power flow control devices for interconnection-related network upgrades associated with new load connections, given that these technologies can be used to rebalance flows quickly and adjusted to mirror actual growth; and (4) mandate deployment of advanced power flow control devices as the default solution for voltage stability management on 100-plus mile AC transmission lines.[2533]

1191. Some commenters suggest that the Commission should collect additional data and require reporting on the deployment of alternative transmission technologies. PIOs and DC and MD Offices of People's Counsel ask the Commission to require that transmission providers explain how they considered alternative transmission technologies in the transmission planning process and if they were not used, why.[2534] DC and MD Offices of People's Counsel assert that data collected from dynamic line ratings should be shared with stakeholders to provide transparency as to the necessity or economic efficiency of certain transmission upgrades, and a mechanism should be implemented to independently review the projected costs and benefits of advanced transmission technologies from an efficiency and cost-allocation perspective.[2535] NASEO states that the Commission should include a requirement for those seeking to make changes to RTOs/ISOs' facilities to provide an analysis of the new technologies and how they meet present and expected future challenges, suggesting that RTOs/ISOs be required to consult with US DOE, the DOE national laboratories, and state energy offices to ensure new technologies are incorporated into Long-Term Regional Transmission Planning.[2536] Certain TDUs argue that the Commission should require transmission planners to document their evaluation of alternative transmission solutions in the transmission planning process, which should include the methods used to integrate grid enhancing technologies alone or in combination with transmission upgrades.[2537]

1192. ENGIE recommends that the Commission require transmission providers to provide a report to the Commission every five years on the deployment and operational analysis of grid enhancing technologies to ensure these technologies are being properly evaluated in Long-Term Regional Transmission Planning.[2538] R Street suggests that the Commission require the incorporation, not just consideration, of advanced transmission technologies, and should require the inclusion of commercially viable

[2524] Pattern Energy Initial Comments at 30 (citing Order No. 881, 177 FERC ¶ 61,179).

[2525] Vistra Initial Comments at 32.

[2526] Invenergy Reply Comments at 16 (citing Invenergy Initial Comments at 14–17).

[2527] WATT Coalition Initial Comments at 5.

[2528] *Id.* at 5–6.

[2529] WATT Coalition Reply Comments at 3.

[2530] WATT Coalition Supplemental Comments at 3.

[2531] WATT Coalition Initial Comments at 8.

[2532] *Id.* at 4.

[2533] Smart Wires Initial Comments at 1, 3–5; WATT Coalition Initial Comments at 3–4.

[2534] DC and MD Offices of People's Counsel Initial Comments at 36; PIOs Initial Comments at 22.

[2535] DC and MD Offices of People's Counsel Initial Comments at 36.

[2536] NASEO Initial Comments at 6–7.

[2537] Certain TDUs Reply Comments at 8–9 (citing OMS Initial Comments at 9; Certain TDUs Initial Comments at 24).

[2538] ENGIE Initial Comments at 6.

technologies on a rolling basis as informed by a regularly updated list of qualifying technologies through, for example, a periodic forum with technology experts from US DOE.[2539] SEIA states that the Commission should host regular technical conferences to discuss improvements and innovations in grid enhancing technologies as experience with these technologies grows.[2540] SEIA states that to determine whether such technologies are feasible, transmission providers should provide the following information to market participants: modeling assumptions, contingency analysis results, asset age, and environmental and footprint constraints.[2541]

1193. Pattern Energy states that the Commission should be mindful that limited supplies of dynamic line ratings, advanced power flow control devices, and SCADA-based implementation equipment (and service providers thereto) may cause shortages that will constrain transmission facility developers and owners.[2542] Pattern Energy adds that, when evaluating the costs to implement such devices, transmission providers may need to assume cost parameters (*e.g.,* cost per mile or cost per installation) for such devices in order to have an ''apples-to-apples comparison.'' [2543]

3. Need for Reform

1194. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not require consideration of alternative transmission technologies in the regional transmission planning process. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the Commission's existing regional transmission planning requirements fail to ensure that transmission providers consider whether to incorporate alternative transmission technologies into regional transmission facilities as part of their regional transmission planning processes and, consequently, fail to ensure that transmission providers are identifying more efficient or cost-effective regional transmission solutions through those processes. As a result, transmission providers overlook or undervalue the benefits of certain alternative transmission technologies and, in turn, undertake relatively inefficient and less cost-effective investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, we find that existing regional transmission planning requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates.

1195. In the NOPR, the Commission stated that commercially available alternative transmission technologies have the potential to improve the operation of new and existing transmission facilities and defer or mitigate the need for new transmission investments.[2544] However, existing regional transmission planning processes are not necessarily designed to consider the benefits that alternative transmission technologies can provide.[2545] Commenters state that some transmission providers are reluctant to implement alternative transmission technologies or that alternative transmission technologies are not consistently evaluated in regional transmission planning in a manner commensurate with the benefits that they can provide.[2546] The failure to consistently consider these technologies in regional transmission planning prevents them from being identified, evaluated, and selected as a more efficient or cost-effective solution to transmission needs, to the detriment of customers that can benefit from their deployment.

1196. The record demonstrates that alternative transmission technologies can provide significant capacity increases when incorporated into transmission facilities, and that such incorporation may provide benefits that outweigh its costs.[2547] For example, a white paper prepared by the Brattle Group highlights several recent examples in which dynamic line ratings, transmission switching, and advanced power flow control devices were deployed to cost-effectively meet transmission needs in SPP, MISO, and other utility service territories.[2548] Additionally, a recent US DOE case study on dynamic line ratings and advanced power flow control devices estimates that these alternative transmission technologies can provide significant production cost savings, net import savings, and avoided curtailment savings.[2549]

1197. We find that the failure to require transmission providers to consider alternative transmission technologies renders the Commission's existing regional transmission planning requirements insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206, that transmission providers consider in Long-Term Regional Transmission Planning and their existing Order No. 1000 regional transmission planning process the alternative transmission technologies discussed below. While the record indicates that some of the alternative transmission technologies enumerated in this final order are sometimes considered in certain transmission planning regions as solutions to specific transmission needs,[2550] we find that inconsistent consideration of alternative transmission technologies in regional transmission planning results in transmission providers overlooking or undervaluing the benefits that these technologies can provide. We find that the reforms concerning the consideration of alternative transmission technologies that we adopt in this final order will render the Commission's existing regional transmission planning requirements just and reasonable, because they will result in transmission providers identifying, evaluating, and selecting regional transmission facilities that are more efficient or cost-effective, which will ensure that Commission-jurisdictional rates are just and reasonable.

4. Commission Determination

1198. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, dynamic line

[2539] R Street Initial Comments at 4.

[2540] SEIA Initial Comments at 21.

[2541] *Id.* at 22.

[2542] Pattern Energy Initial Comments at 29–30.

[2543] *Id.* at 30.

[2544] NOPR, 179 FERC ¶ 61,028 at P 267.

[2545] *See, e.g.,* AEE Initial Comments at 29.

[2546] Certain TDUs Initial Comments at 22–23; Invenergy Initial Comments at 15–16; NASUCA Initial Comments at 7; WATT Coalition Initial Comments at 4.

[2547] *See, e.g.,* WATT Coalition Supplemental Comments at 2–3.

[2548] The Brattle Group, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts* 12–15 (Apr. 20, 2023), *https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf.*

[2549] US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact* v-x (Feb. 2022), *https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.*

[2550] *See* Exelon Initial Comments at 21–23.

ratings and advanced power flow control devices for each identified transmission need. We modify the NOPR proposal to require that, in addition to dynamic line ratings and advanced power flow control devices, transmission providers must consider in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes advanced conductors and transmission switching. Thus, under this modification, transmission providers must consider: (1) dynamic line ratings; [2551] (2) advanced power flow control devices; [2552] (3) advanced conductors; [2553] and (4) transmission switching.[2554] We clarify that transmission providers must consider each of these enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities.[2555] Thus, for each identified transmission need, when evaluating regional transmission facilities for potential selection, transmission providers must consider whether regional transmission facilities that incorporate, or solely consist of, any of the enumerated list of alternative transmission technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies.

1199. However, transmission providers' evaluation of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions. This means that, for the purposes of Long Term Regional Transmission Planning, transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in the same manner that they evaluate any Long-Term Regional Transmission Facility, and in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of this final order. Accordingly, we require transmission providers to measure the required benefits and any additional benefits the transmission providers elect to measure, as discussed in detail in the Required Benefits section,[2556] and use those measured benefits in their evaluation processes to determine if a regional transmission facility that incorporates, or solely consists of, any of the enumerated list of alternative transmission technologies would more efficiently or cost-effectively address Long-Term Transmission Needs. As discussed in detail in the Evaluation and Selection of Long-Term Regional Transmission Facilities section,[2557] that determination would involve applying the transmission providers' selection criteria, which must, among other things, seek to maximize benefits accounting for costs over time without over-building transmission facilities. Similarly, for the purposes of existing Order No. 1000 regional transmission planning processes, transmission providers must consider the benefits of incorporating the enumerated alternative transmission technologies into transmission facilities in the same way that they currently evaluate regional transmission facilities in those existing processes to determine if a regional transmission facility incorporating any of the enumerated transmission technologies would be a more efficient or cost-effective regional transmission solution.

1200. In response to concerns regarding the mandatory consideration of the enumerated alternative transmission technologies for new regional transmission facilities,[2558] and the incremental increase in costs associated with incorporating an alternative transmission technology into new regional transmission facilities or upgrades to existing transmission facilities,[2559] we reiterate that transmission providers must follow the evaluation process and selection criteria in their tariffs. As explained in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, this does not require transmission providers to select any particular Long-Term Regional Transmission Facility to address Long-Term Transmission Needs (*i.e.,* in this case it does not require the selection and deployment of any particular alternative transmission technology with regard to any particular Long-Term Transmission Need).[2560] We recognize that, in addition to considering the costs and benefits associated with incorporating alternative transmission technologies into transmission facilities, transmission providers must continue to follow Good Utility Practice with regard to planning, evaluating, selecting, constructing, operating, and maintaining all transmission facilities, whether such transmission facilities are considered and implemented through existing regional transmission planning processes or as part of Long-Term Regional Transmission Planning as set forth in this final order.[2561]

1201. We find that it is appropriate to require transmission providers to consider whether it may be more efficient or cost-effective to incorporate the enumerated alternative transmission technologies into both new regional transmission facilities and upgrades to existing transmission facilities because the record indicates that such technologies can provide benefits by improving the efficiency of transmission facilities, regardless of whether the facilities are already in-service or yet to be deployed.[2562] We find that incorporating the enumerated

2551 A dynamic line rating is "a transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating, transmission line tension, or transmission line sag." NOPR, 179 FERC ¶ 61,028 at P 259 n.408 (citations omitted); *see also* Order No. 881, 177 FERC ¶ 61,179 at P 7; *Implementation of Dynamic Line Ratings,* 178 FERC ¶ 61,110 at P 1.

2552 Advanced power flow control devices serve a transmission function. These devices can help the system operator control power flows over a given path and can include phase shifting transformers (also known as phase angle regulators) and devices or systems necessary for implementing optimal transmission switching. Advanced power flow control devices allow power to be pushed and pulled to alternate lines with spare capacity leading to maximum utilization of existing transmission capacity. NOPR, 179 FERC ¶ 61,028 at P 270 n.437.

2553 Advanced conductors include present and future transmission line technologies whose power flow capacities exceed the power flow capacities of conventional aluminum conductor steel reinforced conductors. *See* Order No. 2023–A, 186 FERC ¶ 61,199 at 631.

2554 Transmission switching is the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis.

2555 We note that upgrades to existing transmission facilities include both: (1) the incorporation of an alternative transmission technology into an existing transmission facility with no additional changes to the underlying transmission facility (*e.g.,* adding dynamic line ratings to an existing transmission facility); and (2) the incorporation of an alternative transmission technology into an existing transmission facility as part of a larger set of upgrades (*e.g.,* adding dynamic line ratings to a transmission facility that is also being reconductored with a conventional aluminum conductor steel reinforced conductor).

2556 *Supra* Required Benefits section.

2557 *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

2558 CAISO Initial Comments at 6; Exelon Initial Comments at 21–22.

2559 Exelon Initial Comments at 19–20.

2560 *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

2561 *See pro forma* OATT section 28.2 (Transmission Provider Responsibilities) ("The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System.").

2562 *See* WATT Coalition Supplemental Comments at 2–3.

alternative transmission technologies as upgrades to existing transmission facilities has the potential to make the use of existing transmission infrastructure more efficient and optimize the performance of such infrastructure, mitigating or deferring the need for development of new regional transmission facilities.[2563] Adding alternative transmission technologies to new regional transmission facilities may provide cost savings by improving operational efficiency of transmission facilities. Further, incorporating alternative transmission technologies into new transmission facilities may present more benefits and cost less than incorporating such technologies as retrofits after the regional transmission facility is deployed. We further find that requiring transmission providers to consider the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes will ensure that transmission providers more fully consider a broader set of technologies that can address transmission needs more efficiently or cost-effectively.

1202. We clarify that the selection and use any of the enumerated alternative transmission technologies that are incorporated into an existing transmission facility should be treated as an upgrade to an existing transmission facility. Order No. 1000's elimination of any Federal right of right of first refusal for selected transmission facilities does not apply to upgrades to an existing transmission facility.[2564] Therefore, an incumbent transmission provider would be designated to develop any alternative transmission technology that is selected for incorporation into that incumbent transmission provider's existing transmission facilities as the more efficient or cost-effective solution.

1203. With respect to alternative transmission technologies added or deployed on a *new* selected regional transmission facility, we clarify that the transmission developer that is designated to develop the underlying selected regional transmission facility, whether that developer is an incumbent transmission provider or a nonincumbent transmission developer, must also be designated to develop any alternative transmission technologies selected to be incorporated into the regional transmission facility, and thus, would be eligible to use the applicable regional cost allocation method.[2565] For example, in a competitive bidding model, the transmission developer that submits the winning bid for a selected new regional transmission facility that includes an alternative transmission technology would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies. Similarly, in a sponsorship model, the transmission developer that sponsors a new regional transmission facility that includes any alternative transmission technologies would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies, consistent with the selection.

1204. We further clarify that, under a sponsorship model, transmission providers' addition of an alternative transmission technology to a sponsored regional transmission facility proposal that is ultimately selected must not lead to the original sponsored regional transmission facility being labeled as an unsponsored regional transmission facility. Therefore, the sponsoring developer would be eligible to use the regional cost allocation method for the selected new regional transmission facility, as modified with the alternative transmission technology.

1205. We also clarify that, for every competitive transmission development process in a given transmission planning region, transmission providers must identify with sufficient detail in their OATTs the point or points in a given process at which the transmission providers in the transmission planning region will consider the potential use of alternative transmission technologies, including the point at which qualified transmission developers must submit any proposal to incorporate alternative transmission technologies. This clarification is meant to ensure transparency for competing transmission developers and other stakeholders.[2566]

1206. In response to comments that transmission providers should not be required to consider the enumerated alternative transmission technologies in regional transmission planning processes due to the costs and challenges associated with implementation,[2567] we find that the examples in the record of implementation of dynamic line ratings, including ERCOT's experience with dynamic line ratings since 2005 and data from Oncor from 2011 to 2013,[2568] and overall support for the consideration of advanced power flow control devices in transmission planning,[2569] sufficiently demonstrate that transmission providers are capable of considering the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes. Kansas Commission's position that consideration of alternative transmission technologies in regional transmission planning processes should be data-driven and supported by robust analysis demonstrating benefits is consistent with our determinations here.[2570] Therefore, transmission providers must consider the incorporation of these enumerated alternative transmission technologies consistent with the specific requirements for analysis and evaluation of benefits in their OATTs, including those applicable to existing regional transmission planning processes and those required in this final order for Long-Term Regional

[2563] Pattern Energy Initial Comments at 29.

[2564] The Commission stated in Order No. 1000 that the non-incumbent transmission developer reforms do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of 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. In other words, an incumbent transmission provider would be permitted to maintain a Federal right of first refusal for upgrades to its own transmission facilities. Order No. 1000, 136 FERC ¶ 61,051 at P 319 (footnote omitted). The Commission clarified that ''the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility.'' Order No. 1000–A, 139 FERC ¶ 61,132 at P 426. The Commission further clarified that the requirement to eliminate a Federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way. *Id.* P 427.

[2565] *See* FERC, Staff Report, *2017 Transmission Metrics* 8 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf* (describing the two general types of competitive transmission development processes, the ''competitive bidding model'' and the ''sponsorship model'').

[2566] For example, in a competitive bidding model, transmission providers must make clear whether, and if so when, a qualified transmission developer can propose to incorporate alternative transmission technologies into a bid for a selected Long-Term Regional Transmission Facility. This transparency requirement ensures that competing transmission developers will be treated comparably because they will know whether and when they can propose to incorporate any additional alternative transmission technologies into a bid for a regional transmission facility that has been selected.

[2567] *See, e.g.,* ATC Reply Comments at 3.

[2568] Hannon Armstrong Reply Comments at 2–3; WATT Coalition Reply Comments at app. B.

[2569] Ameren Initial Comments at 24–25; EEI Initial Comments at 20–21; Entergy Initial Comments at 29; Exelon Initial Comments at 23.

[2570] Kansas Commission Initial Comments at 19–20.

Transmission Planning.[2571] We acknowledge Mississippi Commission's concerns about deploying alternative transmission technologies without consideration of their costs and note that, to the extent that a transmission provider selects a regional transmission facility that incorporates an enumerated alternative transmission technology, the transmission provider would only do so after evaluating the costs and benefits of that transmission facility, including the incorporation of the alternative transmission technology.[2572]

1207. We disagree with commenter assertions that alternative transmission technologies are only operational tools and that transmission providers cannot rely on any additional capacity created by these technologies for the purpose of meeting transmission needs.[2573] We note that Long-Term Regional Transmission Planning and existing regional transmission planning processes are designed to address a variety of needs, including not only reliability needs but also Long-Term Transmission Needs and economic needs. These processes are well-suited to evaluate the economic benefits of the enumerated alternative transmission technologies, which are relevant to assessing whether a regional transmission facility that incorporates such technologies is more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies. We believe that the particular benefit measurement methods that transmission providers must develop, pursuant to requirements discussed below, to evaluate proposed Long-Term Regional Transmission Facilities can be used to measure the economic benefits of incorporating the enumerated alternative transmission technologies into transmission facilities.[2574] As more fully described above in the Required Benefits section, these benefits include, but are not limited to, methods to measure production cost savings, reduced congestion due to fewer transmission outages, and capacity cost benefits from reduced peak energy losses. Similarly, we find that the enumerated alternative transmission technologies can provide those economic benefits that are already evaluated in existing regional transmission planning processes. Finally, contrary to commenters' concerns, the record here demonstrates that certain alternative transmission technologies are in some cases capable of enhancing reliability and providing additional capacity.[2575]

1208. In response to concerns about administrative burden and assertions that predictions about benefits are speculative,[2576] we find that the potential advantages associated with adopting this reform (*i.e.,* identifying more efficient or cost-effective regional transmission solutions) outweigh the potential administrative and analytical burden. As it pertains to dynamic line ratings, the information needed to inform the calculation of dynamic line ratings should be widely available. For example, NREL has published data on annual averages of windspeeds at 10 meters above the ground that could inform predictions for future wind conditions to facilitate calculations of economic benefits.[2577] For the calculation of the economic benefits associated with dynamic lines ratings, it is appropriate for such calculations to use historical average wind speed and direction data to calculate average increases to transmission line transfer limits for use in benefit calculations. Average predicted wind speeds and direction should be sufficient to inform the transmission provider as to whether the implementation of dynamic line ratings on a specific transmission line may render that line a more efficient or cost-effective regional transmission solution, and such data are widely available.[2578] We acknowledge that there is uncertainty with projections of any kind; however, it is not necessary to understand the precise future wind conditions at a specific future period to assess the expected economic benefits associated with the implementation of dynamic line ratings.

1209. In response to arguments that the Commission should favor transmission provider flexibility with respect to consideration of alternative transmission technologies,[2579] we note that the reforms adopted in this final order provide transmission providers with an appropriate amount of flexibility and do not require the selection of any particular enumerated alternative transmission technology to address any particular transmission need. As previously discussed, this requirement will ensure that transmission providers more consistently consider the costs and benefits associated with incorporating the enumerated alternative transmission technologies into regional transmission facilities. However, we recognize that transmission providers must also continue to follow Good Utility Practice when planning, evaluating, selecting, constructing, operating, and maintaining transmission facilities.

1210. Moreover, we decline to mandate further details on how transmission providers should evaluate the enumerated list of alternative transmission technologies as more efficient or cost-effective solutions to transmission needs, beyond the requirements adopted in this final order. Thus, in response to comments from Smart Wires and WATT Coalition proposing that the Commission mandate either consideration or deployment of advanced power flow control devices in specific situations,[2580] we find that transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to specific transmission needs.[2581]

[2571] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

[2572] Mississippi Commission Reply Comments at 8.

[2573] AEP Initial Comments at 6, 33; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36–37.

[2574] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

[2575] *See infra* P 1241 for a more detailed discussion of the reliability benefits of dynamic line ratings and advanced power flow control devices; *see also* Ameren Initial Comments at 24; Bekaert Supplemental Comments at 1–2; CTC Global Initial Comments at 15.

[2576] ATC Initial Comments at 10; Duke Initial Comments at 30–31 (citing attach. A, Robert Pierce Aff. ¶¶ 8–9); ISO–NE Initial Comments at 40–41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19–20; Large Public Power Initial Comments at 32–33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 22; Pacific Northwest Utilities Initial Comments at 15–16; SERTP Sponsors Initial Comments at 36–37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶ 16; US Chamber of Commerce Initial Comments at 9.

[2577] Data on annual averages of windspeeds at 10 meters above the ground is published by NREL in the form of both maps and tabular data. *See* NREL, *Wind Resource Maps and Data, https://www.nrel.gov/gis/wind-resource-maps.html*. As another example, data on monthly prevailing wind direction is published by the U.S. Department of Agriculture for various cities in all U.S. states in the form of graphical ''wind roses.'' *See* U.S. Dep't. of Agric., National. Weather and Climate Center, *https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/*.

[2578] *See, e.g.,* NREL, *Wind Resource Maps and Data, https://www.nrel.gov/gis/wind-resource-maps.html*; U.S. Dep't of Agric., National Weather and Climate Center, *https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/*.

[2579] Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

[2580] Smart Wires Initial Comments at 1, 3–5; WATT Coalition Initial Comments at 3–4.

[2581] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 153 (noting that transmission providers retain the ultimate responsibility for transmission planning). As Entergy and Exelon attest, advanced power flow control devices are already considered in some transmission planning processes. *See* Entergy Initial Comments at 29; Exelon Initial Comments at 23.

1211. In response to commenters urging the Commission to wait for transmission providers to comply with Order No. 881 before implementing the NOPR proposal,[2582] such concerns are unpersuasive. Public utility transmission providers subject to Order No. 881 are required to implement these requirements by July 12, 2025.[2583] As the Compliance Procedures section of the final order states, the date that transmission providers are required to begin considering the enumerated alternative transmission technologies will be the effective date of the applicable tariff provisions submitted to comply with this final order requirement. The final order also states that transmission providers must submit their compliance filings within ten months of the effective date of this final order, which is 60 days from the date of publication in the **Federal Register**. Moreover, even if the compliance submission deadline falls shortly before Order No. 881's implementation deadline, the operative date here is the date that the tariff revisions proposed in a transmission provider's compliance filing to this final order become effective, which is the effective date requested by the submitting transmission provider and accepted by the Commission.[2584] Consequently, the transmission provider would not need to implement this final order requirement prior to the implementation of Order No. 881 on July 12, 2025 unless it requests, and the Commission accepts, an earlier effective date for its tariff revisions.

1212. Moreover, we find that concerns raised by commenters with respect to the interactions between the requirements that we establish in this final order and Order No. 881 to be speculative. We believe that the requirements to consider the enumerated alternative transmission technologies are separate from (but complementary to) the Commission's requirements in Order No. 881. In Order No. 881, as most relevant here, the Commission required the use of more accurate transmission line ratings using up-to-date forecasts of ambient air temperatures in transmission line ratings. By contrast, regarding the requirement to consider dynamic line ratings in this final order, transmission providers must consider the benefits associated with additional up-to-date transmission line rating input assumptions, specifically wind speed and direction and solar heating intensity.

1213. We disagree with concerns that any mandate to consider dynamic line ratings in this proceeding might complicate the dynamic line ratings notice of inquiry (NOI) proceeding,[2585] or that a mandate to consider dynamic line ratings in this proceeding ignores the record, and the technical challenges identified in, the dynamic line ratings NOI proceeding.[2586] We find such concerns unpersuasive. Any potential future Commission action in the dynamic line ratings NOI proceeding remains hypothetical. Moreover, we expect transmission providers to consider both the benefits of dynamic line rating implementation and the challenges and costs associated with dynamic line rating implementation as part of their consideration of the technology in Long-Term Regional Transmission Planning and their existing regional transmission planning processes.

1214. In response to requests for additional transparency,[2587] we also adopt the NOPR proposal to expand the existing requirement established in Order No. 1000 for transmission providers' evaluation processes to culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected. Specifically, we adopt the NOPR proposal to require that the determination include an explanation that is sufficiently detailed for stakeholders to understand why dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching were or were not incorporated into selected regional transmission facilities.

1215. With regard to the Commission's request for comment on whether to require non-RTO/ISO transmission planning regions to update their energy management systems or make other similar changes if dynamic line ratings are selected as a more efficient or cost-effective regional transmission facility, we require transmission providers to update their energy management systems, if needed to implement dynamic line ratings or any of the alternative transmission technologies. We note that some transmission providers in non-RTO/ISO transmission planning regions may already be able to implement the alternative transmission technologies, and, as a result of the Commission's Ambient-Adjusted Rating requirements in Order No. 881,[2588] may have already updated their energy management systems, and therefore may not need further updates to their energy management systems. However, if a transmission provider must upgrade its energy management systems to implement any of the alternative transmission technologies, then consistent with other requirements in this final order, we require transmission providers to consider any possible energy management system upgrade costs needed to implement the selected alternative transmission technologies as part of their broader consideration of whether transmission facilities that incorporate alternative transmission technologies are more efficient or cost-effective regional transmission solutions. We further reiterate that transmission providers must provide an explanation that is sufficiently detailed for stakeholders to understand why any of the enumerated alternative transmission technologies were, or were not, incorporated into transmission facilities selected in the regional transmission plan for purposes of cost allocation. Moreover, we clarify that this explanation must be sufficiently clear to demonstrate whether the transmission provider did not select transmission facilities that incorporate any of the enumerated alternative transmission technologies, in part or primarily, due to concerns over the costs of upgrading energy management systems.

1216. Finally, we find that WATT Coalition's request to consider incentives for deploying alternative transmission technologies is outside the scope of this proceeding.

B. Specific Alternative Transmission Technologies

1. NOPR Proposal

1217. The Commission sought comment on whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes. The following section discusses comments on specific alternative transmission technologies that transmission providers are required to

[2582] ATC Reply Comments at 4–5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32–33; MISO TOs Initial Comments at 23–24.

[2583] *See MATL LLP*, 185 FERC ¶ 61,028, at P 10 (2023) (stating that July 12, 2025 is the implementation date of Order No. 881(citing Order No. 881, 177 FERC ¶ 61,179 at P 361)).

[2584] *See infra* Compliance Procedures section.

[2585] MISO TOs Initial Comments at 23–24.

[2586] Large Public Power Initial Comments at 32.

[2587] Certain TDUs Reply Comments at 8–9; DC and MD Offices of People's Counsel Initial Comments at 36; ENGIE Initial Comments at 6; PIOs Initial Comments at 22.

[2588] Order No. 881, 177 FERC ¶ 61,179 at P 84.

consider pursuant to the requirements of this final order.

2. Comments on Specific Technologies

1218. AEE notes that dynamic line ratings implementation will increase capacity and provide significant benefits to customers.[2589] Michigan State Entities state that dynamic line ratings hold tremendous value for states like Michigan with cold, cloudy winters, during which there is a greater reliance on transmission to move distant wind generation.[2590]

1219. AEE states that dynamic line ratings and similar technologies are so useful because they improve predictability.[2591] AEE further contends that, in the longer-term, changing conditions will necessitate greater transmission deployment and the need for more transmission capacity, but without considering complementary technologies, the transmission buildout may be less efficient.[2592]

1220. Hannon Armstrong contends that ERCOT's experience with dynamic line ratings since 2005, as well as data from Oncor from 2011 to 2013, demonstrates that this technology can provide significant savings through reduced congestion costs, allow for granular congestion management, and furnish congestion data. According to Hannon Armstrong, real-time dynamic ratings and reliability analysis improve transmission system operation and planning, provide opportunities for congestion mitigation, and could justify the cancellation of planned transmission upgrades. Hannon Armstrong concludes that dynamic line ratings can promote just and reasonable rates without compromising reliability.[2593]

1221. As mentioned above, some commenters warn the Commission of potential reliability and operational impacts of the widespread use of dynamic line ratings.[2594] Entergy explains that it has experienced significantly different weather readings at nearby weather sensors and cautions that the 2003 blackout was partially caused by overestimating the wind in transmission line ratings.[2595]

1222. Some commenters that oppose the use of dynamic line ratings in transmission planning raise concerns about the reliability risks presented by dynamic line ratings.[2596] PJM argues that dynamic line ratings are inappropriate for addressing reliability needs and may introduce operational risk because, for example, forecasted wind might not materialize and the actual real-time ratings would be lower than forecasted.[2597] Southern argues that the assumption of dynamic line ratings leading to additional capacity will likely result in reduced system expansion, which could cause reliability problems in the long run.[2598] Large Public Power and LADWP maintain that there is meaningful cybersecurity risk associated with the communications equipment needed to support dynamic line ratings.[2599] However, WATT Coalition states that both traditional transmission solutions and grid enhancing technologies can result in problems, so the impact of solutions should be evaluated carefully to ensure that a solution to one problem does not create another.[2600]

1223. Some commenters argue that dynamic line ratings are operational in nature and do not belong in the transmission planning process.[2601] Dominion and Exelon state that a transmission provider must plan and build its system for worst case scenarios, which limits the usefulness of dynamic line ratings in transmission planning.[2602] ITC asserts that transmission systems must be planned based on actual transfer capacity under the worst-case scenario, and not on contingent, variable capacity of the type that dynamic line ratings provide.[2603] EEI and Entergy note that the inherent variability and unpredictability associated with wind speed, solar heating intensity, and transmission line tension make dynamic line ratings inappropriate for addressing longer-term system planning objectives.[2604] MISO adds that for transmission planning horizons of five to 20 years or more into the future, it is impossible to predict the real-time conditions on which dynamic line ratings are based.[2605] NRECA explains that dynamic line ratings are not a substitute for an upgraded or new transmission facility.[2606]

1224. Many opposing commenters argue that the benefits of dynamic line ratings are too speculative.[2607] MISO states that dynamic line ratings may not always produce the benefits anticipated, explaining that static ratings are typically based on conservative wind speeds and best-case wind direction, so the assumptions used to develop static ratings are not always worst-case.[2608] ISO–NE asserts that, for example, under summer peak load conditions, the dynamic line rating would be the same as that assumed in the planning study.[2609] Southern cautions that including dynamic line ratings in transmission planning would likely assume additional capacity that may not materialize in real time, increasing congestion.[2610] Large Public Power and MISO TOs argue that dynamic line ratings do not provide sufficient incremental benefits over Ambient Adjusted Ratings to justify the additional expense.[2611]

[2589] AEE Reply Comments at 29 (citing US DOE, *Dynamic Line Ratings Report to Congress 2019* 26 (June 2022), *https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf*).

[2590] Michigan State Entities Initial Comments at 10.

[2591] AEE Reply Comments at 30 (citing MISO Initial Comments at 57–58).

[2592] *Id.*

[2593] Hannon Armstrong Reply Comments at 2.

[2594] Duke Initial Comments at 31–32 (citing attach. A, Robert Pierce Aff. ¶ 11); Entergy Initial Comments at 27–28; MISO Initial Comments at 59–60.

[2595] Entergy Initial Comments at 27–28 (citing U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* 58 (Apr. 2004)).

[2596] ATC Initial Comments at 7, 10; Duke Initial Comments at 31; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; LADWP Initial Comments at 5; NRECA Initial Comments at 53; PJM Initial Comments at 108–109; Southern Initial Comments at 35 (citing Ex. 2, Daryl C. McGee at ¶ 17); SERTP Sponsors Initial Comments at 36–37.

[2597] PJM Initial Comments at 108–109.

[2598] Southern Initial Comments at 35, Ex. 2, Daryl McGee at ¶ 17.

[2599] LADWP Initial Comments at 5; Large Public Power Initial Comments at 35.

[2600] WATT Coalition Reply Comments at 4–5.

[2601] AEP Initial Comments at 33; Dominion Initial Comments at 40; Duke Initial Comments at 5; EEI Initial Comments at 21–22; Entergy Initial Comments at 5–6; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; ISO–NE Initial Comments at 40–41; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); MISO Initial Comments at 57; MISO TOs Initial Comments at 23; NRECA Initial Comments at 52; Pacific Northwest Utilities Initial Comments at 15–16; PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36–37; US Chamber of Commerce Initial Comments at 9.

[2602] Dominion Initial Comments at 40; Exelon Initial Comments at 22.

[2603] ITC Initial Comments at 26.

[2604] EEI Initial Comments at 21; Entergy Initial Comments at 27.

[2605] MISO Initial Comments at 57–58.

[2606] NRECA Initial Comments at 52.

[2607] ATC Initial Comments at 10; Duke Initial Comments at 30 (citing attach. A, Robert Pierce Aff. ¶ 8); ISO–NE Initial Comments at 40–41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19–20; Large Public Power Initial Comments at 32–33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 22; Pacific Northwest Utilities Initial Comments at 15–16; SERTP Sponsors Initial Comments at 36–37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16–17; US Chamber of Commerce Initial Comments at 9.

[2608] MISO Initial Comments at 58.

[2609] ISO–NE Initial Comments at 40–41.

[2610] Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16–17.

[2611] Large Public Power Initial Comments at 32–33; MISO TOs Initial Comments at 24.

1225. Some commenters argue that advanced power flow control devices are appropriate technologies to consider in transmission planning, contrasting them with dynamic line ratings.[2612] Southern states that it generally supports consideration of advanced power flow control devices, and Ameren argues that they may be appropriate in certain circumstances for regional transmission planning.[2613] Additionally, while WATT Coalition agrees that conductor-mounted advanced power flow control devices are limited in impact, it contends that today's ground-mounted versions can significantly increase transfer capacity and integration of renewables.[2614]

1226. Industrial Customers assert that the Commission should compel the use of advanced power flow control devices because they are instrumental to ensuring that transmission lines are fully used to their safest and most efficient potential.[2615] Industrial Customers further argue that the use of advanced power flow control devices will allow for the optimization of transmission lines under various weather conditions.[2616] Smart Wires states that advanced power flow control devices can provide a more affordable means of servicing the type of load growth driving Long-Term Regional Transmission Facilities.[2617] In addition, Smart Wires argues that several system studies have verified that advanced power flow control devices avoid sub-synchronous resonance events on long radial transmission lines, which can result in extensive damage.[2618]

1227. In response to the administrative burden of considering advanced power flow control devices specifically, WATT Coalition states that it provides guidance and evidence of successful modeling schemes for such devices.[2619] WATT Coalition argues that advanced power flow control devices are a valuable solution to limitations of power system studies because they can be adjusted by grid operators for unforeseen grid challenges.[2620] WATT Coalition adds that advanced power flow control devices have a granular dispatchability that can also support real-time operational needs, which may differ from those identified in the transmission planning timeframe.[2621]

1228. Similar to dynamic line ratings, many commenters argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes.[2622] Duke and MISO caution against widespread deployment of advanced power flow control devices.[2623] Duke argues that they should be applied judiciously, and that increased deployment creates a greater risk of wide area cascading events by increasing the probability of the system being in a previously unanalyzed state.[2624] MISO states that, while advanced power flow control devices work best to address specific isolated issues, it is not feasible to coordinate the operation and deployment of these devices en masse, either manually or automatically. According to MISO, deployment of these devices could create other issues, and thus their operation and deployment must be managed on a holistic basis.[2625] MISO further states that advanced power flow control devices could result in continued cascading issues across the system because of the potential widespread impact of adjusting line impedances that may get pushed to other facilities.[2626]

1229. A number of commenters assert that the Commission should expand the list of alternative transmission technologies that must be considered.[2627] Several commenters suggest that the Commission should require transmission providers to consider specific additional technologies in Long-Term Regional Transmission Planning, including storage that performs a transmission function, advanced conductors, transmission switching, topology optimization, and dynamic reactive power devices.[2628] Some Federal legislators agree, offering support for a requirement to consider energy storage, reconductoring using advanced conductors,[2629] and topology optimization.[2630] AEE argues that expanding the list of technologies that must be considered in transmission planning would fulfill the Commission's obligations under the FPA to encourage the adoption of advanced transmission technologies.[2631]

1230. Several commenters urge the Commission to require that storage be considered.[2632] CARE Coalition states that utilities can use storage to defer investments as supply and demand patterns change, allowing them to avoid all-in, 50-year investments in favor of shorter-term flexibility.[2633] CARE Coalition cites a number of ways that storage can improve transmission,

[2612] EEI Initial Comments at 20–21; Entergy Initial Comments at 29; Exelon Initial Comments at 23–24.

[2613] Ameren Initial Comments at 24–25; Southern Initial Comments, Ex. 2, Daryl C. McGee at ¶ 15.

[2614] WATT Coalition Reply Comments at 4.

[2615] Industrial Customers Reply Comments at 13–14.

[2616] *Id.* at 18–19 (citing PPL, Initial Comments, Docket No. AD22–5–000, at 3 (filed Apr. 25, 2022)).

[2617] Smart Wires Initial Comments at 3–4.

[2618] *Id.* at 1, 4.

[2619] WATT Coalition Reply Comments at 3 (citing app. C).

[2620] *Id.* at 4.

[2621] *Id.*

[2622] AEP Initial Comments at 6; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36–37.

[2623] Duke Initial Comments at 31–32; MISO Initial Comments at 59–60.

[2624] Duke Initial Comments at 31–32.

[2625] MISO Initial Comments at 59.

[2626] *Id.* at 60.

[2627] ACEG Initial Comments at 31; ACORE Initial Comments at 16; ACORE Supplemental Comments at 1; AEE Reply Comments at 27–28; Bekaert Supplemental Comments at 1; Breakthrough Energy Initial Comments at 16; CARE Coalition Initial Comments at 2–3; CARE Coalition Reply Comments at 5; Certain TDUs Reply Comments at 8–9; City of New York Reply Comments at 4 (citing PIOs Initial Comments at 84); Clean Energy Associations Initial Comments at 27–28; Clean Energy Associations Reply Comments at 7; CTC Global Initial Comments at 14–15; Industrial Customers Reply Comments at 11; Invenergy Initial Comments at 16; Vermont State Entities Initial Comments at 9.

[2628] Dynamic reactive power is produced from equipment that can quickly change the Mvar level independent of the voltage level. Thus, the equipment can increase its reactive power production level when voltage drops and prevent a voltage collapse. Static VAR compensators, synchronous condensers, and generators provide dynamic reactive power. FERC, Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption* 7 (Feb. 4, 2005), *https://www.ferc.gov/sites/default/files/2020-04/20050310144430-02-04-05-reactive-power.pdf.*

[2629] Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2.

[2630] Environmental Legislators Caucus Supplemental Comments at 2.

[2631] AEE Reply Comments at 27–28, 34 (citing 42 U.S.C. 16422(b)).

[2632] Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 33–34; CAISO Initial Comments at 38; California Commission Initial Comments at 38–40 (citing Jennifer Chen & Devin Hartmann, *Transmission Reform Strategy From A Customer Perspective: Optimizing Net Benefits And Procedural Vehicles R Street Policy Study* 7 (May 2022), *https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf*); CARE Coalition Initial Comments at 2–3; Clean Energy Associations Initial Comments at 30–31; Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36–37; Illinois Commission Initial Comments at 12; Industrial Customers Reply Comments at 11; Joint Consumer Advocates Initial Comments at 13; Michigan Conservative Energy Forum Supplemental Comments at 1; NARUC Initial Comments at 36; National Grid Initial Comments at 3–4; Ohio Conservative Energy Forum Supplemental Comments at 1; OMS Initial Comments at 9; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

[2633] CARE Coalition Initial Comments at 42–43.

including providing voltage support in a transmission-constrained zone, ensuring reliability while repairs are executed, reducing peak loads, increasing capacity on congested lines, directing power flow away from lower capacity transmission lines, and controlling the timing of power flows to remain under thresholds.[2634]

1231. AEP states that the Commission should require better consideration of storage, noting that the technology has advanced significantly in the past several years, yet is still not being deployed as a transmission alternative. AEP cites two reasons for this: (1) despite the multiple uses and benefits of storage, it is currently categorized as only one of the following—transmission, generation, or distribution, and (2) there is no traditional approach that assesses the viability of storage proposals to solve reliability problems. AEP states that, to solve these problems, the Commission should provide more certainty around these questions, including how to schedule, dispatch, and charge storage, as well as guidance on how to assess the value of storage beyond reliability if, for example, the resource is only needed during certain times of year.[2635]

1232. Some commenters suggest that the Commission should require consideration of advanced conductors in Long-Term Regional Transmission Planning.[2636] CTC Global asserts that advanced conductors should be required to be considered because of their ease of installation onto existing structures, cost savings, lower line sag, and power flow increase.[2637] CTC Global adds that even in the case of a total rebuild, advanced conductors can generate more capacity, efficiency, resilience, and reliability than rebuilds using standard conductors.[2638] VEIR notes that if the final order requires the consideration of advanced conductors, the Commission should define advanced conductors to include all advanced conductor technologies, including superconductors.[2639] Bekaert states that the definition of advanced conductors should extend beyond carbon fiber core technologies to also include steel core technologies, which it contends can raise ampacity, reduce line losses, and withstand extreme weather conditions, all while offering a cost-effective solution.[2640]

1233. Some commenters suggest that the Commission should require consideration of transmission switching in Long-Term Regional Transmission Planning.[2641] For example, Illinois Commission states that line switching is a tool to make better use of the extant transmission system.[2642] NASEO states that the use of alternative transmission technologies, including transmission switching, is increasing.[2643] However, MISO argues that grid enhancing technologies that introduce automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered remedial action schemes, which MISO and its transmission owners have attempted to reduce as a matter of Good Utility Practice.[2644]

1234. A number of commenters suggest that the Commission should require consideration of topology optimization in Long-Term Regional Transmission Planning.[2645] Potomac Economics states that network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.[2646] With respect to topology optimization, WATT Coalition recommends that the information provided in the evaluation process should include modeling assumptions, contingency analysis results, asset age and condition, environmental and footprint constraints, etc.[2647] In contrast, SPP states that technologies that optimize transmission system operation should be considered short-term solutions and not a replacement for long-term transmission capacity.[2648]

1235. ITC argues that the Commission should encourage transmission providers to modernize transmission planning criteria to better consider dynamic reactive power devices such as static VAR compensators, static synchronous compensators, and unified power flower controllers. ITC asserts that such technologies provide faster response times to changes in voltage and power factor, relative to capacitor banks and mechanically switched compensation schemes.[2649]

1236. Industrial Customers and Ohio Consumers suggest that the Commission should require the consideration of distributed energy resources in Long-Term Regional Transmission Planning.[2650] Industrial Customers contend that demand response and load-limiting devices should be considered as a way of optimizing the current transmission system, claiming that they are less costly than transmission expansions.[2651] QCo states that the Commission should consider the use of the thermal mass of major buildings as a low-cost method to store energy and provide flexibility to the grid.[2652]

1237. ENGIE asserts that the Commission should require consideration of dynamic transformer rating technology in Long-Term Regional Transmission Planning.[2653]

1238. Exelon is concerned that making a list of technologies to consider in transmission planning will result in a ''time-consuming check-the-box exercise,'' increasing costs and creating litigation opportunities.[2654]

3. Commission Determination

1239. As stated above, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.

1240. In response to comments that dynamic line ratings are operational in nature and are inappropriate in transmission planning, we continue to believe that there is enough real-world operational experience with dynamic

[2634] *Id.* at 42.

[2635] AEP Initial Comments at 33–34.

[2636] ACEG Initial Comments at 31; ACORE Initial Comments at 16; Breakthrough Energy Initial Comments at 15–19; CTC Global Initial Comments at 15–16; DC and MD Offices of People's Counsel Initial Comments at 36–37; Indicated US Senators and Representatives Initial Comments at 2; NASEO Initial Comments at 6; Prysmian Initial Comments at 1; VEIR Initial Comments at 5–6.

[2637] CTC Global Initial Comments at 14–15.

[2638] *Id.* at 15.

[2639] VEIR Reply Comments at 5.

[2640] Bekaert Supplemental Comments at 1–2.

[2641] Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

[2642] Illinois Commission Initial Comments at 12 (citing Pablo A. Ruiz, The Brattle Group, *Transmission Topology Optimization* (Aug. 21, 2017) *https://www.brattle.com/wp-content/uploads/2017/10/7204_transmission_topology_optimization.pdf* (Brattle Group Aug. 2017 Report)).

[2643] NASEO Initial Comments at 6.

[2644] MISO Initial Comments at 60.

[2645] ACORE Initial Comments at 16; CARE Coalition Initial Comments at 2–3; ENGIE Initial Comments at 5–6; Illinois Commission Initial Comments at 11–13 (citing Brattle Group Aug. 2017 Report); Indicated US Senators and Representatives Initial Comments at 2; Potomac Economics Initial Comments at 5; R Street Initial Comments at 4; Tabors Caramanis Rudkevich Initial Comments at 5; WATT Coalition Initial Comments at 6.

[2646] Potomac Economics Initial Comments at 5.

[2647] WATT Coalition Initial Comments at 6.

[2648] SPP Initial Comments at 26.

[2649] ITC Initial Comments at 28.

[2650] Industrial Customers Initial Comments at 35; Ohio Consumers Initial Comments at 34.

[2651] Industrial Customers Reply Comments at 11.

[2652] QCo Initial Comments at 1–3.

[2653] ENGIE Initial Comments at 5–6.

[2654] Exelon Initial Comments at 23–24.

line ratings for transmission providers to be able to reasonably project their likely operations and, as such, the benefits that regional transmission facilities that incorporate dynamic line ratings can provide over the transmission planning horizon.[2655] Dynamic line ratings have the ability to increase transmission line ratings, and thus permit more economic energy transfers in most intervals,[2656] which, in turn, could result in benefits (including, but not limited to, production cost savings, reduced congestion due to fewer transmission outages resulting from improved situational awareness, and capacity cost benefits from reduced peak energy losses) that we require transmission providers to evaluate in Long-Term Regional Transmission Planning,[2657] and in their existing regional transmission planning processes.

1241. We acknowledge commenter concerns about the potential effects that the widespread use of dynamic line ratings or advanced power flow control devices could have on reliability.[2658] But while these technologies cannot solve all reliability needs, as noted above, the record here demonstrates that alternative transmission technologies are in certain circumstances capable of enhancing reliability and providing additional capacity.[2659] We recognize that, either dynamic line ratings or advanced power flow control devices, on their own, may be unlikely to resolve certain reliability needs that are assessed based on worst case conditions.[2660] We also reiterate that nothing in this final order changes transmission providers' obligations to conduct transmission planning in a manner that ensures the long-term reliability of the bulk electric system.[2661] However, we find that dynamic line ratings and advanced power flow control devices can also confer reliability benefits. For example, in Order No. 881, the Commission found that, by accounting for ambient air temperatures in transmission line ratings, transmission providers can reliably increase power transfer capability, which results in significant reliability benefits.[2662] Such reliability benefits also apply to dynamic line ratings. Specifically, by accounting for actual wind conditions, dynamic line ratings can also reliably increase transfer capability and thereby provide reliability benefits. Similarly, as Ameren describes, it may be more efficient to use advanced power flow control devices, which can address stability limitations by allowing for greater use of a transmission facility.[2663]

1242. Additionally, Long-Term Regional Transmission Planning evaluates Long-Term Regional Transmission Facilities based on multiple benefits, and some existing regional transmission planning processes focus on economic benefits, while others may consider multiple benefits, including economic benefits. At a minimum, regional transmission solutions incorporating dynamic line ratings are appropriately considered as part of these processes. Given the potentially substantial economic benefits of dynamic line ratings, we find that it is important for transmission providers to consider dynamic line ratings in Long-Term Regional Transmission Planning and their existing regional transmission planning processes so as to ensure that they identify more efficient or cost-effective regional transmission facilities for selection.

1243. We also disagree with commenters that argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes. We find that the potential benefits of using advanced power flow control devices are sufficient to merit their consideration in Long-Term Regional Transmission Planning and existing regional transmission planning processes. For example, as Ameren states, where a transmission line is stability-limited from carrying more power, the use of advanced power flow controls may address the limitation and allow greater use of the line. Ameren also notes that advanced power flow controls may be beneficial in a situation where a transmission line that needs to be upgraded traverses sensitive environmental areas.[2664] Moreover, as Entergy and Exelon attest, advanced power flow control devices are already considered in some transmission planning processes.[2665] As discussed above, we modify the NOPR proposal to add two additional alternative transmission technologies to the list of enumerated alternative transmission technologies required to be considered in Long-Term Regional Transmission Planning and existing regional transmission planning: advanced conductors and transmission switching. We find that advanced conductors may greatly increase the capacity of transmission facilities, and thus a new regional transmission facility or upgrade to an existing transmission facility that incorporates advanced conductors may be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not incorporate such technologies. Consistent with Order No. 2023, we note that advanced conductors can increase transmission line ratings, providing more "headroom" on the system to address normal and contingency conditions.[2666] We clarify that the definition of advanced conductors that we adopt in this final order constitutes a range of permissible present and future technologies, and is defined relative to conventional aluminum conductor steel reinforced conductors. Therefore, advanced conductors include, but are not limited to, superconducting cables, advanced composite conductors, advanced steel cores, high temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors. We find that such advanced conductors can result in lower line sag and increased power flow and can be installed on existing transmission structures, thereby offering ease of installation.[2667]

1244. We agree with commenters that suggest that transmission switching should be added to the list of alternative transmission technologies that must be considered in Long-Term Regional Transmission Planning and existing regional transmission planning processes.[2668] We clarify that, in this final order, we define transmission switching as the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis. Transmission switching can be used to route energy around areas with high congestion and

[2655] NOPR, 179 FERC ¶ 61,028 at P 276.

[2656] Hannon Armstrong Reply Comments at 1–3.

[2657] *See supra* Required Benefits section.

[2658] *See, e.g.,* CAISO Initial Comments at 41–42.

[2659] *See supra* P 1206 of this section.

[2660] For example, as ISO–NE explains, the dynamic line rating may be the same as the rating already assumed in the planning study as transmission providers may need to assume worst case weather inputs to transmission line ratings. ISO–NE Initial Comments at 40–41.

[2661] See, for example, TPL–001–5.1, Transmission System Planning Performance Requirements, which establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

[2662] Order No. 881, 177 FERC ¶ 61,179 at P 85.

[2663] Ameren Initial Comments at 24.

[2664] *Id.*

[2665] Entergy Initial Comments at 29; Exelon Initial Comments at 23.

[2666] Order No. 2023, 184 FERC ¶ 61,054 at P 1597.

[2667] CTC Global Initial Comments at 14–15.

[2668] Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

improve the overall transfer capability of the system. In doing so, transmission switching may provide additional economic or reliability benefits, which could therefore render a transmission facility that uses transmission switching a more efficient or cost-effective alternative than a regional transmission facility that does not use transmission switching. In response to MISO's concern that automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered remedial action schemes,[2669] we note that there are appropriate applications for transmission switching that offer the potential to be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not use one of the enumerated alternative transmission technologies. For example, the record indicates that network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.[2670]

1245. We decline to add storage that performs a transmission function to the list of enumerated alternative transmission technologies. The Commission has determined that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis of either how a particular electric storage resource would be operated or the requirements set forth in an OATT governing selection of such electric storage resources.[2671] In the context of regional transmission planning, we continue to find that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis, and therefore decline to generically require the consideration of storage that performs a transmission function in regional transmission planning processes.

1246. For the following reasons, we also decline to add topology optimization to the list of enumerated alternative transmission technologies because it is technically much more challenging to implement. We clarify that topology optimization is not specific to individual transmission facilities but instead is the act of determining the optimal use of the transmission system, which may involve many different transmission facilities. Additionally, the optimal use of the transmission system may frequently change depending on system conditions throughout the operating day. By contrast, transmission switching focuses on opening or closing transmission elements in pre-determined circumstances based on prior analyses well in advance of the operational time horizon.[2672] We do not find that it is necessary to require the consideration of topology optimization in regional transmission planning processes currently. While topology optimization software has been used to identify potential system reconfiguration actions that could result in a reduction in real-time congestion, it has not yet been deployed due to computational complexity. Specifically, given the size and complexity of the power grid and the large number of potential optimization solutions, finding optimization solutions in the necessary real-time timelines is extremely difficult and doing so risks poor model performance and lower quality solutions, which, in turn, could adversely impact reliability. While simplifications might be possible, such simplifications risk oversimplifying, which, in turn, could also jeopardize reliability.[2673]

1247. Finally, we decline to add further additional alternative transmission technologies suggested by commenters.[2674] We note that, while commenters express support for the concept of considering additional alternative transmission technologies, in general, we do not believe that the record is sufficient to include these additional technologies on the enumerated list of alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning and existing regional transmission planning processes at this time. However, we note that nothing in this final order precludes transmission providers from considering other alternative transmission technologies or other potential solutions in their Long-Term Regional Transmission Planning and existing regional transmission planning processes.

VI. Regional Transmission Cost Allocation

A. Cost Allocation for Long-Term Regional Transmission Facilities

1. Cost Allocation Methods for Long-Term Regional Transmission Facilities

a. NOPR Proposal

1248. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise their OATTs to include: (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[2675] may voluntarily agree to a cost allocation method; or (3) a combination thereof.[2676]

1249. The Commission proposed to define a Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning. The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable method.[2677] The Commission proposed to define a State Agreement Process as an *ex post* cost allocation process that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning, which may apply to an individual Long-Term Regional Transmission Facility or a portfolio of such Facilities grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement

[2669] MISO Initial Comments at 60.

[2670] Potomac Economics Initial Comments at 5.

[2671] Order No. 2023, 184 FERC ¶ 61,054 at P 1599.

[2672] *See supra* P 1243 of this section on transmission switching. We recognize that there may be overlap between the concepts of transmission switching and topology optimization. As noted below, nothing in this final order precludes transmission providers from considering topology optimization solutions as an alternative transmission technology, if they so choose.

[2673] US DOE, *Advanced Transmission Technologies* 11–15 (Dec. 2020), *https://www.energy.gov/oe/articles/advanced-transmission-technologies-report.*

[2674] *See supra* PP 1235–1237.

[2675] The definition of Relevant State Entities is discussed below. *See infra* Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

[2676] NOPR, 179 FERC ¶ 61,028 at P 302. The Commission explained that, for example, a ''combination'' approach may entail: (1) providing a Long-Term Regional Transmission Cost Allocation Method for certain types of Long-Term Regional Transmission Facilities and providing a State Agreement Process for others; or (2) providing for cost allocation for a Long-Term Regional Transmission Facility, portfolio, or type of such facilities partially based on a Long-Term Regional Transmission Cost Allocation Method and partially based on funding contributions in accordance with a State Agreement Process. *Id.* P 302 n.510.

[2677] *Id.* P 302 n.508.

can be reached). If the Commission approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method.[2678]

1250. The Commission also proposed to apply the cost allocation reforms only to new Long-Term Regional Transmission Facilities. Therefore, these proposed reforms would neither provide grounds for re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of any final order in this proceeding, nor would they apply to the cost allocation methods associated with regional transmission facilities that address shorter-term transmission needs driven by reliability and/or economic considerations.[2679]

1251. In addition, the Commission stated that, to the extent transmission providers believe that their existing cost allocation approaches comply with the requirements adopted in any final order in this proceeding, including those related to the agreement of Relevant State Entities, they could make such demonstration in their compliance filings in response to any final order.[2680]

b. Comments

i. Interest in the Proposed Cost Allocation Reforms

1252. Some commenters offer general support for the cost allocation reforms proposed in the NOPR.[2681]

1253. Several commenters indicate support for the proposal to require transmission providers to revise their OATTs to include: (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.[2682] Clean Energy Buyers state that this proposal will provide certainty in the cost allocation process, lessening disputes that may delay transmission development.[2683] ITC suggests that the Commission look to OMS' role in State Agreement Processes as a guide for how other transmission planning regions can foster state participation in Long-Term Regional Transmission Planning.[2684] AEP asserts that clear rules set in advance provide the regulatory certainty necessary to support large, long-term transmission investments and ensure customers and developers know how the associated costs will be allocated.[2685]

1254. New Jersey Commission states that a hybrid method that allocates costs partially *ex ante,* based on reliability and economic benefits, and partially *ex post,* through a State Agreement Process/negotiated participant funding approach, could have value, arguing that negotiated cost allocations could reduce litigation and make it easier to construct beneficial transmission facilities.[2686] SEIA supports a combination of a Long-Term Regional Transmission Cost Allocation Method and a State Agreement Process, asserting that states should be allowed to assume the costs of new transmission facilities to serve their needs.[2687]

ii. Requested Clarifications and Concerns Related to the Proposed Cost Allocation Reforms

1255. Some commenters raise concerns and request clarifications on the proposed reforms. For example, BP contends that, in the case of a multi-value project, it is unclear whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method, as opposed to all of the costs.[2688] NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Transmission Facilities.[2689]

1256. Other commenters urge flexibility with respect to cost allocation methods and state involvement,[2690] citing regional differences,[2691] to improve the likelihood of achieving consensus between affected states.[2692] OMS stresses the need for flexibility with respect to cost allocation methods to realize the NOPR's overall objectives of cost-effective regional transmission expansion.[2693] Louisiana Commission, however, asserts that, whichever cost allocation method is adopted, it should not allow a majority to impose costs upon non-consenting states.[2694]

1257. Shell states that the Commission should require coastal transmission providers to explain how their Long-Term Regional Transmission Planning processes facilitate transmission planning and cost allocation for offshore wind.[2695] Shell further asserts that the Commission should require all transmission providers to account for the risk of free-ridership in their OATTs, arguing that regardless of the cost allocation method applied, the Commission should ensure that first-movers are protected from free-ridership.[2696]

1258. Some commenters express concerns about the proposed State Agreement Process.[2697] Dominion states that a practical challenge in implementing the proposed reforms will be whether having an *ex ante* cost allocation method combined with alternative proposals or some combination thereof creates an additional opportunity to debate and challenge a transmission project, resulting in delays and increased costs.[2698]

[2678] *Id.* P 302 n.509.

[2679] *Id.* P 314.

[2680] *Id.*

[2681] *E.g.,* Breakthrough Energy Initial Comments at 6; Business Council for Sustainable Energy Initial Comments at 2; California Democratic Representatives Supplemental Comments at 2; Joint Consumer Advocates Initial Comments at 13; OMS Initial Comments at 9; Pine Gate Initial Comments at 45; WE ACT Initial Comments at 5.

[2682] Certain TDUs Initial Comments at 2, 7; City of New Orleans Council Initial Comments at 9–10; Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; ISO–NE Initial Comments at 37; ITC Initial Comments at 28; Kentucky Commission Chair Chandler Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at PP 302–303); Michigan Commission Initial Comments at 8; NARUC Initial Comments at 51; NESCOE Initial Comments at 10; New York Commission and NYSERDA Initial Comments at 12–13; New York TOs Initial Comments at 18; North Carolina Commission and Staff Initial Comments at 15–16; NYISO Initial Comments at 48–49; OMS Initial Comments at 10; Pacific Northwest State Agencies Initial Comments at 27; Pattern Energy Initial Comments at 18; PIOs Initial Comments at 64; PJM States Initial Comments at 9–10; Resale Iowa Initial Comments at 2, 12.

[2683] Clean Energy Buyers Initial Comments at 26–27.

[2684] ITC Reply Comments at 28–29.

[2685] AEP Initial Comments at 35.

[2686] New Jersey Commission Initial Comments at 17, 25.

[2687] SEIA Initial Comments at 24.

[2688] BP Initial Comments at 12.

[2689] NARUC Initial Comments at 49–50.

[2690] *See, e.g.,* Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5–6, 11, 13.

[2691] *See, e.g.,* Dominion Initial Comments at 45; Ohio Commission Federal Advocate Initial Comments at 11.

[2692] New York TOs Initial Comments at 18; *see also* Northwest and Intermountain Initial Comments at 18.

[2693] OMS Initial Comments at 10.

[2694] Louisiana Commission Initial Comments at 33–34.

[2695] Shell Initial Comments at 17.

[2696] *Id.* at 25, 28.

[2697] We also address comments regarding the State Agreement Process in more detail below. *See infra* Proposals Relating to the Design and Operation of State Agreement Processes section.

[2698] Dominion Initial Comments at 52.

iii. Concerns With the Proposed Cost Allocation Reforms

1259. Some commenters generally oppose the proposed reforms. For example, Southern states that the proposal to establish a specific cost allocation process before Long-Term Regional Transmission Planning has identified actual transmission projects is too abstract to work in practice and will most likely fail to attract requisite state support.[2699] Southern further asserts that the NOPR's proposed cost allocation processes do not satisfy the second prong of the Commission's FPA section 206 burden of proof to establish a just and reasonable replacement rate.[2700] Pacific Northwest State Agencies oppose the option in the NOPR proposal that allows transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method without involving states in its development.[2701]

iv. Comments on Specific Aspects of the Proposed Cost Allocation Reforms

(a) Use of Existing Cost Allocation Methods for Long-Term Regional Transmission Facilities

1260. Some commenters assert that they should be able to use existing cost allocation methods for Long-Term Regional Transmission Planning, with some RTOs/ISOs[2702] and RTO/ISO stakeholders[2703] supporting these arguments. Other commenters support the Commission permitting transmission providers to keep their existing processes that involve states in cost allocation decisions.[2704] PPL supports using the existing regional cost allocation structures as a default. PPL asserts that any change to the existing cost allocation method will require an FPA section 205 filing, and interested parties, including the states, may intervene and provide testimony and evidence regarding the appropriateness of any benefit used.[2705]

1261. APS states that it agrees with the Commission that collaboration with Relevant State Entities is a positive approach to transmission planning, but it believes that the current cost allocation process is appropriate and should not be altered. APS, noting that the Commission has determined that additional complexities and contentiousness may result from expanding the transmission planning horizon to 20 years, argues that underlying cost causation principles will apply, and, therefore, existing cost allocation processes remain appropriate.[2706]

1262. Similarly, PJM contends that the need for new or expanded transmission facilities identified through Long-Term Regional Transmission Planning would fall under the reliability or market efficiency studies that it performs today, and, therefore, the Commission should permit it to use its existing *ex ante* cost allocation methods as the default cost allocation method for transmission facilities selected through Long-Term Regional Transmission Planning (absent agreement by all affected states on an alternate method). PJM states that using its existing *ex ante* approaches will provide consistency and certainty in assigning cost responsibility.[2707] PJM States disagree, arguing that the Commission should not presume that existing cost allocation methods are just and reasonable without a full examination and input from retail regulators. According to PJM States, the factors that make PJM's existing cost allocation methods just and reasonable in the short term may not exist in the long term.[2708]

1263. PJM further requests that the Commission clarify that if a transmission provider proposes to use an existing cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning, such a proposal may not be a cause for relitigating the use of that method for transmission projects selected prior to the issuance of the final order.[2709] MISO states that if existing cost allocation methods previously were determined to comply with the Order No. 1000 regional cost allocation principles, the Commission should not require another demonstration and should clarify that its proposals do not require transmission providers to modify or set aside any existing regional cost allocation method.[2710] Relatedly, ITC argues that the Commission should allow for streamlined compliance plans from transmission providers that already have substantial long-range planning processes in place.[2711]

1264. PIOs proffer that having two distinct cost allocation methods can be unjust, unreasonable, and unduly discriminatory even if those methods are reasonable on their own, and that multiple cost allocation methods may create uncertainty, which the Commission has recognized can be a barrier to transmission development.[2712] PIOs therefore request that the Commission: (1) require transmission providers to identify and justify differences between Long-Term Regional Transmission Planning and near-term cost allocation; (2) find that compliance filings that create opportunities for ''cost allocation arbitrage'' may not be approved; and (3) require transmission providers to demonstrate that their current Order No. 1000 cost allocation methods are just, reasonable, and not unduly discriminatory or preferential.[2713]

1265. Dominion requests that the Commission clarify that any cost allocation method directed through this rulemaking proceeding is: (1) limited to Long-Term Regional Transmission Facilities; and (2) limited to Order No. 1000 transmission planning regions.[2714]

1266. Clean Energy Associations request that the Commission adopt *pro forma* cost allocation provisions that would allow for regional variation where cost allocation practices are consistent with or superior to the requirements adopted in any final order. For example, Clean Energy Associations state, if vertically integrated public utilities subject to state-jurisdictional integrated resource planning can demonstrate that the state planning process appropriately identifies needs and assigns costs based on future planned generation consistent with state policies, certain requirements may not be applicable.[2715]

(b) Comments on Whether Filing an Ex Ante Cost Allocation Method Should Be Required

1267. Some commenters support a requirement that transmission providers submit an *ex ante* cost allocation

[2699] Southern Initial Comments at 6–7.

[2700] *Id.* at 7 n.7.

[2701] Pacific Northwest State Agencies Initial Comments at 24–25.

[2702] *See, e.g.,* MISO Initial Comments at 61, 68; PJM Initial Comments at 116; SPP Initial Comments at 28–29.

[2703] *See, e.g.,* Ameren Initial Comments at 25–27; Avangrid Initial Comments at 28; Dominion Initial Comments at 3, 45; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13–14; PJM States Initial Comments at 11–12; Virginia Commission Staff Initial Comments at 6.

[2704] Avangrid Initial Comments at 28; Dominion Reply Comments at 11; Omaha Public Power Initial Comments at 4.

[2705] PPL Initial Comments at 28–29.

[2706] APS Initial Comments at 11–12.

[2707] PJM Initial Comments at 115.

[2708] PJM States Reply Comments at 5.

[2709] PJM Initial Comments at 115 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

[2710] MISO Initial Comments at 61.

[2711] ITC Initial Comments at 29–30.

[2712] PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 297).

[2713] *Id.* at 72.

[2714] Dominion Initial Comments at 49–50.

[2715] Clean Energy Associations Initial Comments at 36.

method or methods that would apply to all Long-Term Regional Transmission Facilities either in place of, or as a backstop for, a State Agreement Process.[2716] For example, Grid United suggests that the Commission mandate that transmission providers develop *ex ante* cost allocation methods for selected Long-Term Regional Transmission Facilities to remove development and financial uncertainty, provide transparency in how benefits are calculated, and ensure that cost allocation is roughly commensurate with the distribution of benefits.[2717]

1268. MISO TOs state that *ex ante* cost allocation provides upfront certainty, explaining that MISO's *ex ante* processes work well and align with past Commission findings regarding the difficulty of supporting new construction without knowing who will pay for it and the importance of working out cost allocation up front, rather than ''relitigating it'' each time a transmission project is proposed.[2718] MISO TOs do not oppose states voluntarily agreeing to assume cost responsibility for regional transmission projects, which Commission policy already permits via participant funding, but argue that states that want to voluntarily assume cost responsibility for part or all of a transmission project should do so during the transmission planning process (*i.e.,* when considering potential transmission projects) rather than after projects have been selected, so that those approving such projects can know how costs will be allocated.[2719]

1269. New Jersey Commission states that the Commission should not allow transmission providers to use cost allocation methods that rely solely on participant funding, such as PJM's State Agreement Approach. New Jersey Commission explains that such mechanisms are an unjust and unreasonable method for allocating the costs of holistically planned multi-driver projects and portfolios because if transmission projects can only be built if one or more states agree to assume 100% of the resulting costs, more expensive projects or portfolios that maximize net benefits to the transmission planning region will go unbuilt, ultimately driving up system-wide costs.[2720]

1270. Illinois Commission states that *ex ante* approaches should be the primary cost allocation method and include state input and approval, and that the State Agreement Process should only be used for exceptions in which public policy goals fall outside of the scope of Long-Term Regional Transmission Planning. Illinois Commission expresses concerns because it understands the NOPR to state that transmission projects without an *ex ante* cost allocation method would not be funded unless states decide to pay for them through a State Agreement Process, which could create more expensive and siloed transmission planning that does not meet future transmission needs.[2721]

1271. Many commenters express concerns about the optionality of the proposal and argue that it is necessary to have a default *ex ante* cost allocation method where agreement cannot be reached among states and to preserve FPA section 205 filing rights.[2722] Numerous entities support an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities to be used in the event a State Agreement Process does not result in an agreed-upon cost allocation method.[2723]

1272. For example, Minnesota State Entities contend that an *ex ante* process that allocates costs at least roughly proportional to benefits should be required as the default cost allocation method unless states can agree on an *ex post* cost allocation method within 90 days. Minnesota State Entities also recommend that the Commission require RTOs/ISOs to use postage stamp cost allocation as the default cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities) unless the RTO/ISO can develop an alternate cost allocation method that all affected states agree on within 90 days following RTO/ISO approval.[2724]

1273. PIOs argue that without a default cost allocation method, transmission may be held up in stakeholder processes or by project-by-project litigation to assign costs.[2725] PIOs further caution that the Long-Term Regional Transmission Planning framework is at risk without an *ex ante* cost allocation method because successful negotiation of a State Agreement Process for each transmission project would be unwieldy and create opportunities for free-ridership and obstructionism.[2726] Similarly, AEE argues that relying on a State Agreement Process would not be just and reasonable and likely would stall the transmission planning and cost allocation process.[2727] Acadia Center and CLF assert that where the Commission anticipates that states will fail to agree, it should establish the Long-Term Regional Transmission Cost Allocation Method because, otherwise, ineffective regional transmission planning processes will remain in place.[2728]

1274. SEIA argues that having a default cost allocation method will ensure that transmission that promotes public policy will be built even in the face of disagreement.[2729] R Street states that the Commission should require schedule discipline and a default cost allocation provision for circumstances where states cannot agree, which can include an accelerated Commission-led arbitration process or Commission application of preestablished criteria.[2730]

1275. Georgia Commission asserts that, if Relevant State Entities cannot reach agreement, or if a Relevant State Entity forgoes its opportunity to participate in the State Agreement Process, there should be a default Long-Term Regional Transmission Cost Allocation Method when clear benefits have been identified for a specific transmission facility or portfolio of facilities.[2731]

1276. NYISO does not object to the final order directing each transmission provider to adopt an *ex ante* cost allocation method for transmission projects selected through Long-Term

[2716] *See, e.g.,* Grid United Initial Comments at 6; Illinois Commission Initial Comments at 16–17; Minnesota State Entities Initial Comments at 6; MISO TOs Initial Comments at 45–48; PIOs Initial Comments at 70; RMI Supplemental Comments at 2–3.

[2717] Grid United Initial Comments at 6.

[2718] MISO TOs Initial Comments at 45–48 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 557, 561; Order No. 1000, 136 FERC ¶ 61,051 at P 499).

[2719] *Id.* at 48–49.

[2720] New Jersey Commission Initial Comments at 24.

[2721] Illinois Commission Initial Comments at 16–17.

[2722] ACORE Supplemental Comments at 1; APPA Initial Comments at 6, 44–45; Environmental Groups Supplemental Comments at 2–3; Evergreen Action Initial Comments at 6; Georgia Commission Initial Comments at 9; ITC Initial Comments at 30–31; Massachusetts Attorney General Initial Comments at 18–21; TAPS Initial Comments at 4–5, 24–26; WIRES Initial Comments at 12–13.

[2723] Evergreen Action Initial Comments at 6; Exelon Initial Comments at 24, 26; Georgia Commission Initial Comments at 8–9; ITC Initial Comments at 30–31; Massachusetts Attorney General Initial Comments at 18–20, 22–23; MISO Initial Comments at 67–68; Northwest and Intermountain Initial Comments at 18; Pine Gate Initial Comments at 7; PIOs Initial Comments at 67; TAPS Initial Comments at 4–5, 24–25; WIRES Initial Comments at 12–13.

[2724] Minnesota State Entities Initial Comments at 6–7.

[2725] PIOs Initial Comments at 70.

[2726] *Id.* at 67.

[2727] AEE Reply Comments at 15, 34.

[2728] Acadia Center and CLF Initial Comments at 31 (citing NOPR, 179 FERC ¶ 61,028 at P 310).

[2729] SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

[2730] R Street Initial Comments at 4, 12.

[2731] Georgia Commission Initial Comments at 9.

Regional Transmission Planning for use when an alternative method is not identified in a process that involves the state. NYISO references, as an example, the process cited in the NOPR whereby the New York Commission plays a role in determining the cost allocation method for public policy transmission projects.[2732]

1277. Exelon supports requiring a default *ex ante* cost allocation method that would act as a backstop cost allocation method should the states in a transmission planning region fail to negotiate an alternative cost allocation method for a transmission project or portfolio of projects. Exelon states that failure to reach an agreement on cost allocation should not act as a barrier to needed transmission, and whatever mechanism is developed for receiving state input should not allow one or more states to thwart the goals of other states and stakeholders.[2733]

1278. PPL asserts that the proposal to require a Long-Term Regional Transmission Cost Allocation Method may not solve the problem of states refusing to site transmission projects where they do not agree on cost allocation, but in some transmission planning regions, it may nevertheless be helpful to have a default cost allocation method.[2734]

1279. Some commenters oppose requiring a default *ex ante* cost allocation method, whether on its own or in combination with a State Agreement Process.[2735] For example, California Commission asserts that the Commission should not mandate an *ex ante* cost allocation method if states cannot agree to a cost allocation method by a certain date.[2736] NRG states that the Commission should focus on voluntary cost allocation and should not use involuntary cost allocation as a substitute to participant-funded interconnection and transmission expansion.[2737] NRG states that it would be unrealistic to expect productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state.[2738]

1280. SERTP Sponsors express concern that requiring state agreements or an *ex ante* cost allocation method before transmission projects are identified is unworkable because regulators in the Southeast will likely insist that the projects first be identified and their benefits and costs determined before the projects are selected and cost allocation commitments are made.[2739] SERTP Sponsors state that expecting states to accept a cost allocation for transmission projects that they do not support, based on a process they have not chosen, and to which they do not assign value or benefit for retail ratepayers, will not succeed.[2740] Alabama Commission agrees with SERTP Sponsors, stating that the State Agreement Process is a more appropriate and equitable mechanism for allocating the costs of Long-Term Regional Transmission Facilities and should be the sole cost allocation method.[2741] Similarly, US Chamber of Commerce contends that state utility regulators would risk not adequately protecting their constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design and/or benefits of a proposed regional transmission facility.[2742]

1281. EPSA argues that because long-term transmission planning horizons introduce uncertainty risk that customers must bear, cost allocation should be voluntary to the maximum degree possible.[2743] Louisiana Commission opposes proceeding with any transmission projects selected in Long-Term Regional Transmission Planning without the voluntary cost allocation agreement of all impacted states.[2744] Mississippi Commission asserts that the Commission should not require a default *ex ante* cost allocation method because doing so would bias and undermine cost allocation negotiations between states.[2745] Mississippi Commission further argues that the Commission should clarify that state agreement on cost allocation for each transmission facility, or portfolio of facilities, is what is required, not simply involvement in the stakeholder process.[2746]

1282. Xcel opposes a mandated *ex ante* cost allocation method, stating that the industry engaged in more effective long-term transmission planning before Order No. 1000, and that the Commission should give transmission planning regions flexibility to identify potential solutions before identifying the cost allocation for those solutions. In addition, Xcel supports allowing transmission planning regions flexibility to tailor the benefits evaluated to the purpose of the study and project, citing MISO's experience with Long-Range Transmission Planning.[2747] Similarly, Southern states that the Commission should not require an *ex ante* cost allocation process, but if it does, it should adopt the NOPR proposal to allow transmission providers to determine the appropriate benefits.[2748]

1283. Duke asserts that the Commission has provided no support other than pointing to Order No. 1000 as to why Long-Term Regional Transmission Facilities should have a default *ex ante* cost allocation method.[2749] Duke explains that if states disagree with the need, benefits, and cost allocation determined in Commission-jurisdictional transmission planning processes, then states are likely to exercise their jurisdiction over siting and retail cost allocation to thwart development of a Long-Term Regional Transmission Facility.[2750] Duke asks that the Commission clarify that transmission providers may rely solely on a State Agreement Process and are not required to adopt an *ex ante* default Long-Term Regional Transmission Cost Allocation Method.[2751] Duke argues that an *ex post* cost allocation method from a fully litigated Commission proceeding is a more durable solution than a default *ex ante* cost allocation, which may be similarly litigated but also delay siting approvals.[2752]

1284. NESCOE requests that the Commission confirm that if a transmission provider files a State Agreement Process, the transmission provider does not need to file an *ex ante* cost allocation method, and the time period for a state-negotiated alternate cost allocation method would not apply.[2753]

v. Other Cost Allocation Method Proposals

1285. ACEG recommends having a threshold level of voltage or capacity above which a transmission facility would receive regional cost allocation

[2732] NYISO Initial Comments at 49 (citing NOPR, 179 FERC ¶ 61,028 at P 300 & n.500).

[2733] Exelon Initial Comments at 26.

[2734] PPL Initial Comments at 26.

[2735] *See, e.g.,* Louisiana Commission Initial Comments at 30, 34; NRG Initial Comments at 6; SERTP Sponsors Initial Comments at 28; US Chamber of Commerce Initial Comments at 9–10.

[2736] California Commission Initial Comments at 57.

[2737] NRG Initial Comments at 6, 16.

[2738] *Id.* at 20.

[2739] SERTP Sponsors Initial Comments at 3, 28.

[2740] *Id.* at 20.

[2741] Alabama Commission Initial Comments at 9.

[2742] US Chamber of Commerce Initial Comments at 9–10.

[2743] EPSA Initial Comments at 7.

[2744] Louisiana Commission Initial Comments at 17–18, 30.

[2745] Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3.

[2746] Mississippi Commission Initial Comments at 28.

[2747] Xcel Initial Comments at 11–12.

[2748] Southern Initial Comments at 27.

[2749] Duke Initial Comments at 37.

[2750] *Id.* at 3, 35–36.

[2751] *Id.* at 33.

[2752] *Id.* at 3, 36–37.

[2753] NESCOE Initial Comments at 66–67.

because the benefits of transmission depend directly on having a robust grid capable not only of receiving diverse generation but also of withstanding extreme weather.[2754]

1286. Shell argues that the Commission should be open to non-traditional cost allocation methods, such as the sharing of benefits when a defined benefit/cost ratio threshold is exceeded, to achieve the goal of minimizing first-mover risk. Shell contends that sharing the cost of interconnection-related network upgrades between first movers and subsequent customers is common in the industry and points to ISO–NE, PJM, and MISO as examples of RTOs/ISOs that have revised their OATTs to attempt to address this concern.[2755]

1287. ELCON notes that regardless of the funding mechanism or approved cost allocation method, benefits and risks may change over time as Long-Term Scenarios are updated and needs and solutions are reassessed. Therefore, ELCON states that the three-year reexamination of Long-Term Scenarios should also review cost allocation to ensure that cost causers and willing beneficiaries continue to be assessed the costs of a transmission project over its lifetime.[2756]

1288. Xcel proposes that transmission planning regions rely on scenario-based studies that reflect load-serving entity inputs regarding projected generation expansion, expected types and locations of generators, and expected load. Xcel states that the load-serving entities could then adjust their resource plans in light of the resulting costs and benefits. Xcel asserts that this flexibility would result in consensus-based cost allocation tied to the transmission that load-serving entities actually need and would reduce the reluctance to participate in planning as the outcomes could be adjusted to accommodate adjustments in load-serving entity needs and expectations.[2757] Xcel also argues that the Commission should make clear that it is sometimes appropriate to allocate costs to generators, and that transmission access rights allocation should follow cost allocation.[2758]

1289. Certain TDUs argue that the Commission should require any *ex ante* cost allocation method to follow a ''beneficiary pays'' approach, as opposed to the default, postage stamp load ratio share model.[2759] Certain TDUs claim that the advantages of adopting a beneficiary-pays cost allocation approach are well documented, as the circumstances appropriate for a postage stamp allocation are not necessarily present when allocating costs for Long-Term Regional Transmission Facilities.[2760] R Street similarly asserts that the final order should adhere to the beneficiary-pays principle to allocate the costs of both transmission and interconnection-related network upgrades.[2761]

1290. Cypress Creek contends that where ''cost allocation would hamper the use of contingent needs as a driver for multi-value projects,'' there should be a hybrid approach. Specifically, Cypress Creek suggests allocating costs up to the lesser of: (1) the cost of necessary reliability improvements and (2) the benefit-cost threshold ratio of the multi-value project to the party that needs the improvements. Cypress Creek suggests that the remaining costs be allocated according to multi-value project rules.[2762]

c. Commission Determination

1291. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities. Specifically, we modify the NOPR proposal to require, instead of just permit, transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Methods for Long-Term Regional Transmission Facilities that are selected. We adopt the NOPR's proposed definition, with modification, of Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. In addition to this required Long-Term Regional Transmission Cost Allocation Method, we also permit transmission providers to revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process. Any State Agreement Process that transmission providers voluntarily propose to include in their OATTs would not comply with the requirements of this final order unless Relevant State Entities indicate to the transmission providers that Relevant State Entities have agreed to that process during the Engagement Period (which we discuss further below).[2763]

1292. While we permit transmission providers to include a State Agreement Process in their OATTs to determine cost allocation methods for selected Long-Term Regional Transmission Facilities if the process is agreed to by Relevant State Entities, it cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities. As discussed below, we find that sole reliance on a State Agreement Process to determine a cost allocation method for selected Long-Term Regional Transmission Facilities will not achieve the objectives of this final order. Additionally, we modify the NOPR proposal to require that, if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop. In other words, if a Long-Term Regional Transmission Facility or portfolio of such Facilities is selected but a State Agreement Process fails to result in a Commission-accepted cost allocation method for that facility or facilities, then their costs must be allocated through the Long-Term Regional Transmission Cost Allocation Method or Methods that would otherwise apply in the absence of a State Agreement Process (*i.e.,* the backstop Long-Term Regional Transmission Cost Allocation Method).[2764] We clarify that, if the transmission providers have more than one Long-Term Regional Transmission Cost Allocation Method on file, then the

[2754] ACEG Initial Comments at 63.

[2755] Shell Initial Comments at 25–28.

[2756] ELCON Initial Comments at 19.

[2757] Xcel Initial Comments at 18.

[2758] *Id.* at 12–13.

[2759] Certain TDUs Initial Comments at 2, 7.

[2760] *Id.* at 8–9.

[2761] R Street Initial Comments at 4, 12.

[2762] Cypress Creek Reply Comments at 12.

[2763] We discuss the definition of Relevant State Entities below. *See infra* the Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

[2764] For example, transmission providers could file two Long-Term Regional Transmission Cost Allocation Methods, A and B. In this example, Method A would apply only to Long-Term Regional Transmission Facilities under 300 kV. Method B would apply to Long-Term Regional Transmission Facilities at or above 300 kV only if an agreed-upon State Agreement Process fails to result in a Commission-accepted cost allocation method. If, on compliance, transmission providers propose more than one Long-Term Regional Transmission Cost Allocation Method, they must specify to which Long-Term Regional Transmission Facilities each Long-Term Regional Transmission Cost Allocation Method applies.

method that would otherwise apply to the specific selected Long-Term Regional Transmission Facility would serve as the backstop Long-Term Regional Transmission Cost Allocation Method.

1293. We continue to find that facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[2765] Nevertheless, we find that the requirement for transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs is necessary because, if transmission providers were to rely solely on a State Agreement Process to determine the cost allocation for Long-Term Regional Transmission Facilities and that process fails to result in agreement, there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs. As a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized. Moreover, transmission providers would likely rely on relatively inefficient or less cost-effective transmission facilities to address the identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further find that reliance solely on a State Agreement Process would suffer from the same flaws that led the Commission to require *ex ante* cost allocation for selected regional transmission facilities in Order No. 1000, as the allocation of transmission costs can be contentious and prone to litigation in multi-state transmission planning regions.[2766] Requiring a Long-Term Regional Transmission Cost Allocation Method, even when transmission providers also have a State Agreement Process in effect, provides a level of certainty critical to the development of needed Long-Term Regional Transmission Facilities.

1294. As noted above, the relevant Long-Term Regional Transmission Cost Allocation Method on file would serve as a backstop if the State Agreement Process does not result in a Commission-accepted cost allocation method for the selected Long-Term Regional Transmission Facility or portfolio of such Facilities subject to the State Agreement Process. This outcome could occur for several reasons. For instance, Relevant State Entities may not reach agreement on a cost allocation method pursuant to the terms of a State Agreement Process and the transmission providers may choose not to file any cost allocation method. In another instance, transmission providers may choose not to file a cost allocation method agreed to pursuant to a State Agreement Process and also choose not to file any alternative cost allocation method. And finally, the Commission might not accept a cost allocation method that results from a State Agreement Process and that transmission providers submit to the Commission for filing under FPA section 205 to the extent that it does not satisfy the requirement to allocate costs at least roughly commensurate with estimated benefits or is otherwise unjust or unreasonable.[2767]

1295. In response to NRG's and Mississippi Commission's concerns that a Long-Term Regional Transmission Cost Allocation Method could undermine productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state,[2768] on balance, we find that this possibility is outweighed by the risk that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solution to Long-Term Transmission Needs may not have an associated cost allocation method absent this requirement, and thus would be unlikely to be developed.[2769] As we explain above, the lack of a cost allocation method for selected Long-Term Regional Transmission Facilities would likely result in transmission providers relying on relatively inefficient or less cost-effective transmission facilities to address identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further note that a Long-Term Regional Transmission Cost Allocation Method provides certainty that the costs of Long-Term Regional Transmission Facilities for which a State Agreement Process does not result in a Commission-approved cost allocation method will be allocated in a manner that the Commission has found to be just and reasonable and not unduly discriminatory or preferential.

1296. In response to the arguments by SERTP Sponsors, Alabama Commission, and Louisiana Commission emphasizing the importance of voluntary cost allocation among states,[2770] along with Mississippi Commission's request for clarification that state agreement to a cost allocation method be required for any Long-Term Regional Transmission Facility under this final order,[2771] we note that Relevant State Entities will have the opportunity to provide their views on cost allocation methods during the Engagement Period, as discussed further below. Following this Engagement Period, Relevant State Entities may agree to, and ask the transmission providers to file, a State Agreement Process, which, if accepted by the Commission, would be the cost allocation process used by the transmission providers in the transmission planning region prior to the use of the relevant Long-Term Regional Transmission Cost Allocation Method as a backstop. Further, as discussed in the Proposals Relating to the Design and Operation of State Agreement Processes section below, during the Engagement Period or State Agreement Process, Relevant State Entities will have an opportunity to agree to and ask transmission providers to file a Long-Term Regional Transmission Cost Allocation Method. Thus, there are multiple opportunities for Relevant State Entities to voluntarily

[2765] NOPR, 179 FERC ¶ 61,028 at P 301.

[2766] Order No. 1000, 136 FERC ¶ 61,051 at PP 498–499; *see also S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d at 70 (finding that the Commission reasonably balanced the benefits and claimed burdens of Order No. 1000's reforms in concluding that the requirement that each transmission provider include in its OATT a method(s) for allocating *ex ante* the costs of new regional transmission facilities ''would reduce conflicts and 'aid in the development and construction of new transmission' '' and allow stakeholders ''to determine *ex ante* 'that the benefits associated with [a particular] set of transmission facilities outweigh the costs' '' (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 499, 669)).

[2767] *See PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178, at P 33 (2022) (''In light of the New Jersey state law, the New Jersey [State Agreement Approach] Projects will benefit customers throughout New Jersey, and thus we find that allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects.'') (footnote omitted).

[2768] Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3; NRG Initial Comments at 20.

[2769] As discussed below in the Requirement that Transmission Providers Seek Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section, we decline to define what constitutes agreement among Relevant State Entities and, as such, we do not require unanimous agreement of Relevant State Entities participating in the Engagement Period on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.

[2770] SERTP Sponsors Initial Comments at 3, 20, 28; Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 17–18, 30.

[2771] Mississippi Commission Initial Comments at 28.

negotiate a cost allocation method for Long-Term Regional Transmission Facilities.

1297. We find that US Chamber of Commerce's concern, that state utility regulators might fail to protect constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design or benefits of a proposed regional transmission facility, is misplaced.[2772] Any cost allocation method(s) that transmission providers propose, be it as a result of a State Agreement Process or a Long-Term Regional Transmission Cost Allocation Method, must allocate costs in a manner that is at least roughly commensurate with estimated benefits, as discussed further below.[2773] For the same reasons, we disagree with EPSA's contention that, because Long-Term Regional Transmission Planning introduces uncertainty risk that customers must bear, all the relevant cost allocation methods on file should be voluntary.[2774]

1298. We also acknowledge Duke's concerns that a default *ex ante* cost allocation method could delay siting approvals and Xcel's concerns associated with a mandated *ex ante* cost allocation method claiming that the industry engaged more effectively in long-term transmission planning before Order No. 1000.[2775] We note that another modification to the NOPR proposal that we adopt, as described below, allows State Agreement Processes to occur before, as well as up to six months after, selection of Long-Term Regional Transmission Facilities. This modification helps to address Duke's and Xcel's concerns by providing Relevant State Entities with an opportunity to agree on a cost allocation method for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) after selection. However, we find that, even if such an agreement on a State Agreement Process cost allocation method cannot be achieved, on balance, the greater certainty that *ex ante* cost allocation methods provide to allow the development of Long-Term Regional Transmission Facilities outweighs the concerns that Duke and Xcel express.

1299. Furthermore, we find that allowing the use of a State Agreement Process in addition to a Long-Term Regional Transmission Cost Allocation method will assist in the development of Long-Term Regional Transmission Facilities by taking into account state preferences. SEIA and New Jersey Commission support such flexibility.[2776] We agree with New Jersey Commission that negotiated cost allocation methods may reduce litigation and make it easier to construct needed transmission facilities.[2777] We recognize Dominion's concerns that implementing a State Agreement Process with an *ex ante* approach could lead to delays; [2778] however, we find that both the backstop Long-Term Regional Transmission Cost Allocation Method, combined with a six-month limit after selection for deliberations under any State Agreement Process and the filing of any resulting cost allocation method, as detailed below, should limit such delays.

1300. Next, we adopt the NOPR proposal to apply the cost allocation reforms in this final order only to new Long-Term Regional Transmission Facilities. We find that this reform does not apply to regional reliability and economic transmission facilities that are selected pursuant to the existing Order No. 1000 regional transmission planning processes. We find, instead, that the existing Commission-accepted *ex ante* regional cost allocation methods adopted pursuant to Order No. 1000 should continue to apply to those regional reliability and economic transmission facilities. We find no basis in the record to conclude that these existing regional cost allocation methods should change, given that this final order does not alter existing regional reliability and economic transmission planning processes. We believe that this distinction between cost allocation methods for regional reliability and economic transmission projects selected under existing Order No. 1000 regional transmission planning processes and those for new Long-Term Regional Transmission Facilities selected through Long-Term Regional Transmission Planning will prevent the re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of this final order. In addition, we find this distinction to be consistent with our decision not to apply Long-Term Regional Transmission Cost Allocation Methods to transmission facilities other than new Long-Term Regional Transmission Facilities.[2779]

1301. We disagree with PIOs that allowing different cost allocation methods to apply to different regional transmission planning processes is unjust and unreasonable.[2780] We find that because Long-Term Regional Transmission Planning is a more long-term, forward-looking, and comprehensive transmission planning process than existing Order No. 1000 regional transmission planning processes, it is appropriate for transmission providers to consider, following the Engagement Period, whether different cost allocation methods should apply to selected Long-Term Regional Transmission Facilities.

1302. With respect to the potential use of existing regional cost allocation methods as Long-Term Regional Transmission Cost Allocation Methods, as well as assertions that existing cost allocation methods or current existing processes for state involvement in cost allocation decisions could be used for Long-Term Regional Transmission Planning,[2781] we adopt the NOPR proposal that, to the extent transmission providers believe that their existing cost allocation methods comply with the requirements adopted in this final order, they may demonstrate in their compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final order. This approach is consistent with the approach that the Commission took in Order No. 1000, in which the Commission declined commenter requests to decide in the rulemaking itself whether existing cost allocation methods complied with the requirements of Order No. 1000 and instead required transmission providers to demonstrate on compliance that their existing cost allocation methods met the rulemaking's requirements.[2782]

[2772] US Chamber of Commerce Initial Comments at 9–10.

[2773] *See infra* Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities.

[2774] EPSA Initial Comments at 7.

[2775] Duke Initial Comments at 36; Xcel Initial Comments at 12.

[2776] New Jersey Commission Initial Comments at 25; SEIA Initial Comments at 24.

[2777] New Jersey Commission Initial Comments at 17.

[2778] Dominion Initial Comments at 52.

[2779] As the Commission noted in the NOPR, the Commission took a similar approach with respect to its cost allocation reforms in Order No. 1000. *See* NOPR, 179 FERC ¶ 61,028 at P 314 n.517 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 565).

[2780] PIOs Initial Comments at 71.

[2781] *See, e.g.,* Ameren Initial Comments at 25–27; APS Initial Comments at 11–12; Avangrid Initial Comments at 28;Dominion Initial Comments at 3, 45; Dominion Reply Comments at 11; MISO Initial Comments at 61, 68; NYISO Initial Comments at 9, 50; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13–14; PJM Initial Comments at 116; PJM States Initial Comments at 11–12; SPP Initial Comments at 28–29; Virginia Commission Staff Initial Comments at 6.

[2782] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 565; Order No. 1000–A, 139 FERC ¶ 61,132 at P 747.

1303. We disagree with PPL's contention that existing regional cost allocation methods accepted by the Commission should be considered the ''default.'' The Commission accepted such *ex ante* regional cost allocation methods based on demonstrations of how they met the six Order No. 1000 regional cost allocation principles. We appreciate, as the Commission has recognized, that some existing regional cost allocation methods are complex, stakeholder-approved constructs and that some are specifically designed to apply to broad portfolios of transmission projects, such as MISO's regional cost allocation method for Multi-Value Projects.[2783] However, as described above, to the extent that transmission providers propose on compliance to use an existing regional cost allocation method as a Long-Term Regional Transmission Cost Allocation Method, the transmission providers must demonstrate that such existing regional cost allocation method, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final order. We disagree with ITC's contention that the Commission should allow for streamlined compliance plans for transmission providers that already have long-range transmission planning processes; we reiterate that we require transmission providers to submit proposed cost allocation processes on compliance with this order so that the Commission may evaluate whether those processes comply with the requirements of this final order.

1304. BP raises a concern that it is not clear, in the case of a multi-value project, whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method as opposed to all of the costs. With the exception of Long-Term Regional Transmission Facilities that one or more Relevant State Entities or interconnection customers agree to voluntarily fund, we clarify that all costs associated with a selected Long-Term Regional Transmission Facility must be allocated using the applicable Long-Term Regional Transmission Cost Allocation Method or Methods, or an applicable Commission-accepted cost allocation method that results from a State Agreement Process.[2784]

1305. In response to requests that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods,[2785] we reiterate that any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent.[2786] Load ratio share, which charges transmission customers in proportion to their use of the transmission system as measured by their relative share of load, is a cost allocation method that may be consistent with the beneficiary-pays approach. The Commission will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits on a fact-specific basis, relying on the record in a given proceeding.

1306. In response to commenters that request flexibility in cost allocation,[2787] we believe that the approach to cost allocation for Long-Term Regional Transmission Facilities that we adopt in this final order provides transmission providers and their stakeholders, and in particular Relevant State Entities, with the flexibility needed to address regional differences. Specifically, we find that the flexibility to submit one *or more* Long-Term Regional Transmission Cost Allocation Methods, as well as the flexibility to submit an additional State Agreement Process, accommodate regional differences.

1307. We decline to adopt additional requirements with respect to cost allocation that we did not propose in the NOPR, such as Shell's request to require coastal transmission providers to explain how their Long-Term Regional Transmission Planning facilitates cost allocation for offshore wind.[2788] We find that the record in this proceeding does not support imposing this or other additional requirements. Regarding certain cost allocation requirements suggested by commenters,[2789] including ACEG's suggestion for implementing a voltage threshold level above which a transmission facility would receive regional cost allocation,[2790] we find such proposals to be beyond the scope of this proceeding. The Commission did not make such proposals in the NOPR.

2. Requirement That Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities

a. NOPR Proposal

1308. The Commission proposed to require transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2791] The Commission proposed to require transmission providers in each transmission planning region to: (1) explain how the proposed Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof reflects the agreement of Relevant State Entities; or (2) to the extent agreement of Relevant State Entities cannot be obtained, explain the good faith efforts by the relevant transmission provider(s) to seek agreement from such entities before proposing a Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2792]

1309. The Commission proposed to define Relevant State Entities for purposes of the Long-Term Regional Transmission Planning cost allocation requirements as ''any state entity responsible for utility regulation or siting electric transmission facilities

[2783] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.,* 142 FERC ¶ 61,215, at P 434 (2013); *Sw. Power Pool, Inc.,* 144 FERC ¶ 61,059, at P 347 (2013).

[2784] *See supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section. Moreover, in the Local Transmission Planning Inputs in the Regional Transmission Planning Process section below, we provide flexibility to transmission providers to propose a cost allocation method for right-sized replacement transmission facilities.

[2785] *See* Certain TDUs Initial Comments at 2, 7, 8–9; R Street Initial Comments at 4, 12.

[2786] The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 87 (citing *Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d at 1285); *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 10 (''[T]he principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits.''); *ICC* v. *FERC I,* 576 F.3d at 476 (''To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.'').

[2787] *See, e.g.,* Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5–6, 11, 13.

[2788] Shell Initial Comments at 17.

[2789] Cypress Creek Reply Comments at 12; ELCON Initial Comments at 19; R Street Initial Comments at 4, 12; Shell Initial Comments at 25–28; Xcel Initial Comments at 12–13, 18.

[2790] ACEG Initial Comments at 63.

[2791] NOPR, 179 FERC ¶ 61,028 at P 303.

[2792] *Id.* P 303.

within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.'' [2793]

1310. The Commission proposed to require transmission providers in each transmission planning region to seek to determine whether, for all or a subset of Long-Term Regional Transmission Facilities, Relevant State Entities agree to: (1) a Long-Term Regional Transmission Cost Allocation Method; (2) a State Agreement Process; (3) forgo a role in determining the cost allocation approach for Long-Term Regional Transmission Facilities; or (4) some combination thereof.[2794]

1311. The Commission proposed to afford transmission providers in each transmission planning region flexibility in the process by which they seek agreement from Relevant State Entities and to require transmission providers to provide the state entities with flexibility with regard to defining what constitutes ''agreement'' among the Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.[2795] Although the Commission proposed to provide transmission providers flexibility in determining what constitutes state agreement, the Commission preliminarily found that, for each state, a single entity should be designated as the voting or representative entity to avoid confusion or over-representation by a single state in a multi-state voting process.[2796]

1312. Noting that the Relevant State Entities may forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, the Commission proposed that in the event that the Relevant State Entities do so, the Commission would require transmission providers 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.[2797] The Commission explained that it was not proposing to impose any requirements on states to participate in processes to establish regional cost allocation methods for Long-Term Regional Transmission Facilities.[2798]

[2793] *Id.* P 304.

[2794] *Id.* P 305.

[2795] *Id.* P 306.

[2796] *Id.* P 304.

[2797] *Id.* P 307.

[2798] *Id.* P 308.

b. Comments

i. State Involvement in Cost Allocation Proposals

1313. Many commenters generally support states having a role negotiating proposed cost allocation methods.[2799] However, some commenters emphasize the importance of involving all stakeholders, and not just Relevant State Entities, in this reform. Clean Energy Buyers argue that the Commission should require transmission providers to allow all stakeholders (not just states) to participate in, or at least comment on, the development of the Long-Term Regional Transmission Cost Allocation Method and to recognize the importance of states and all other stakeholders.[2800] Similarly, NEPOOL asserts that state involvement should not diminish the opportunity for stakeholder involvement from all market participants in the electric industry.[2801] APPA asserts that while coordination with state regulators in cost allocation may aid in developing beneficial and cost-effective transmission projects, the perspectives of state regulators on cost allocation should not be elevated above those of other stakeholders.[2802]

1314. Idaho Power states that the Commission should continue to allow flexibility for transmission planning regions to determine the appropriate level of state involvement.[2803] Pacific Northwest Utilities agree, stating that mandating additional state participation could be burdensome and problematic.[2804]

1315. MISO states that the Commission should not extend any state involvement that may be adopted pursuant to the final order to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final order.[2805] MISO Coops state that MISO provides a stakeholder forum where states' voices are heard, and the final order should not diminish stakeholder processes that are effective today.[2806]

1316. Other commenters raise concerns about increased state involvement in cost allocation decisions. For example, Vistra asserts that a prioritized role for states in cost allocation is more likely to create new challenges than ease development, and observes that it may be difficult to coordinate state interests in multi-state transmission planning regions versus single-state transmission planning regions.[2807] Six Cities opposes enhanced roles for Relevant State Entities, suggesting that the proposed reforms represent neither an appropriate oversight role for states under the FPA, nor a logical extension of Order No. 890 and Order No. 1000 policies.[2808]

1317. ACEG and Georgia Commission agree with the Commission's proposed definition of Relevant State Entities.[2809] ACEG and Dominion also support the proposal to have a single entity designated as the voting representative for the state.[2810] MISO agrees that having a single entity designated for each state and/or applicable jurisdiction as the voting or representative entity for that state/jurisdiction makes sense, but notes that the City of New Orleans is an independent member of OMS separate from the Louisiana Commission and therefore may need to be considered a separate jurisdiction.[2811] Louisiana Commission voices similar concerns.[2812] North Carolina Commission and Staff state that it may be appropriate for different state entities to be designated for different roles,[2813] and Duke asserts that the Commission should clarify that within a state there

[2799] *See, e.g.,* AEP Initial Comments at 35; Ameren Initial Comments at 25; American Municipal Power Initial Comments at 12; Arizona Commission Initial Comments at 11; Clean Energy Associations Initial Comments at 35; Clean Energy Buyers Initial Comments at 28–29; Clean Energy States Initial Comments at 7; Cross Sector Representatives Supplemental Comments at 1; Duke Initial Comments at 35; ELCON Initial Comments at 17; ISO–NE Initial Comments at 2; Georgia Commission Initial Comments at 8–9; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 28; Joint Consumer Advocates Initial Comments at 13; Maryland Energy Administration Initial Comments at 2; Massachusetts Attorney General Initial Comments at 19; Michigan Commission Initial Comments at 8; MISO Initial Comments at 61; NARUC Initial Comments at 45 (citing NOPR, 179 FERC ¶ 61,028 at PP 303–308), 46; New York Commission and NYSERDA Initial Comments at 1; NESCOE Initial Comments at 54; North Carolina Commission and Staff Initial Comments at 2; North Dakota Commission Initial Comments at 4; NRG Initial Comments at 6; NYISO Initial Comments at 49; OMS Initial Comments at 10; PacifiCorp and NV Energy Initial Comments at 15; PIOs Initial Comments at 64; Resale Iowa Initial Comments at 2; US Chamber of Commerce Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 at P 288); Virginia Commission Staff Initial Comments at 2; WIRES Initial Comments at 12.

[2800] Clean Energy Buyers Initial Comments at 29.

[2801] NEPOOL Initial Comments at 9.

[2802] APPA Initial Comments at 42.

[2803] Idaho Power Initial Comments at 10.

[2804] Pacific Northwest Utilities Initial Comments at 13.

[2805] MISO Initial Comments at 71.

[2806] MISO Coops Initial Comments at 2.

[2807] Vistra Initial Comments at 2, 27–28.

[2808] Six Cities Initial Comments at 7.

[2809] ACEG Initial Comments at 65–66; Georgia Commission Initial Comments at 8.

[2810] ACEG Initial Comments at 65–66; Dominion Initial Comments at 48 n.99.

[2811] MISO Initial Comments at 66.

[2812] Louisiana Commission Initial Comments at 33.

[2813] North Carolina Commission and Staff Initial Comments at 17.

may be multiple Relevant State Entities.[2814]

1318. Some commenters generally agree with the Commission's proposed definition of Relevant State Entities but request that the definition be expanded or clarified to include self-regulated public power utilities and cooperatives.[2815] TAPS argues that a multi-state voting process, as proposed, could fail to represent public power and cooperatives' interests.[2816] NRECA contends that a more inclusive approach would be to use ''relevant electric regulatory authority,'' which includes a state public utility commission and the governing board of a cooperative or public power utility.[2817] Large Public Power proposes to grant state and municipal utilities representation on a load ratio share basis.[2818]

1319. NASUCA urges the Commission to clarify that where applicable, an approved state cost allocation process should include agreement by a state's utility consumer advocate.[2819] California Energy Commission recommends expanding the definition of Relevant State Entities to include any groups directly or indirectly affected by the construction of a project, such as Native American Tribes,[2820] and NESCOE requests that the definition of Relevant State Entity be amended to accommodate individual transmission planning regions' particular approaches toward state involvement in cost allocation requirements, such as NESCOE managers designated by each New England Governor to represent that state's interests.[2821]

1320. Nevada Commission requests flexibility in the term Relevant State Entity.[2822] New Mexico RETA urges flexibility to account for state involvement of other entities not accounted for in the definition of Relevant State Entities, including state authorities specifically designated to assist in developing new electric transmission facilities (like New Mexico RETA).[2823]

1321. ACEG recommends that the Commission clarify that existing processes, such as SPP's Regional State Committee, MISO's OMS, and ISO–NE's New England States Committee, should be used to determine the Relevant State Entity for each state, unless another process is demonstrated to be superior.[2824]

1322. SERTP Sponsors assert that which Relevant State Entity or Entities would be appropriate for a particular state will be a function of state law.[2825] Pennsylvania Commission states that the Commission's proposed definition of Relevant State Entity is imperfect and may result in multiple entities within a single state being a Relevant State Entity, given that the Commission refers to utility regulation or siting authority in the definition, but a state's legislature could have delegated this different authority among different administrative agencies.[2826]

ii. Requirement To Seek Agreement

1323. Many commenters generally support requiring transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2827]

1324. Avangrid states that state input and collaboration is crucial to the transmission planning process, and that intensive state (and other stakeholder) participation and consensus-building will help to ensure that transmission will not be overbuilt.[2828] SoCal Edison contends that without agreement among states on the respective benefits and share of related costs, the development of multi-state transmission projects will be nearly non-existent.[2829] PPL supports transmission providers seeking agreement with the states on cost allocation methods, as well as voluntary coordination with states, which PPL argues will make public policy projects more likely to succeed.[2830]

1325. NYISO and ISO–NE support state entities playing a role in determining the cost allocation method for transmission solutions to Long-Term Transmission Needs.[2831] ISO–NE contends that states should be responsible for determining the cost allocation mechanism for policy-based, long-term transmission facility investments because they are uniquely situated to balance the benefits and costs of transmission investments intended to advance their policy goals.[2832]

1326. Mississippi Commission argues that opponents of state involvement in Long-Term Regional Transmission Planning fail to recognize the existing state regulatory role in siting electricity generation, transmission, and distribution facilities.[2833]

1327. In addition, some commenters support the agreement of states when determining a Long-Term Regional Transmission Cost Allocation Method. City of New Orleans Council comments that it is essential that state and local regulators agree to any Long-Term Regional Transmission Cost Allocation Method to ensure that the costs borne by retail customers are just and reasonable and not unduly discriminatory or preferential.[2834] SoCal Edison concurs on the necessity for states to reach agreement.[2835] Southern argues that unless state regulators agree to transmission project selection and cost allocation, transmission projects that result from the Commission's proposed Long-Term Regional Transmission Planning are not likely to come to fruition.[2836]

iii. Seek Changes To, Raise Concerns About, or Oppose the Requirement To Seek Agreement

1328. Some commenters support requiring transmission providers to seek agreement with Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or a combination thereof, but propose changes to the proposal. For example,

[2814] Duke Initial Comments at 38–39.

[2815] American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42–43 (citing 16 U.S.C. 796(7), (15)); California Municipal Utilities Initial Comments at 17; MISO Coops Initial Comments at 3–4; Six Cities Initial Comments at 10.

[2816] TAPS Initial Comments at 5, 26–27.

[2817] NRECA Initial Comments at 56–57.

[2818] Large Public Power Initial Comments at 41.

[2819] NASUCA Initial Comments at 10–11.

[2820] California Energy Commission Initial Comments at 3.

[2821] NESCOE Initial Comments at 57.

[2822] Nevada Commission Initial Comments at 13.

[2823] New Mexico RETA Initial Comments at 8–9 (citing NOPR 179 FERC ¶ 61,028 at P 304).

[2824] ACEG Initial Comments at 66.

[2825] SERTP Sponsors Initial Comments at 28–29.

[2826] Pennsylvania Commission Initial Comments at 15.

[2827] *See, e.g.,* Acadia Center and CLF Initial Comments at 29–30; Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; Entergy Initial Comments at 29–30; Georgia Commission Initial Comments at 8–9; ISO–NE Initial Comments at 37–38; Louisiana Commission Initial Comments at 30; Michigan Commission Initial Comments at 8; NARUC Initial Comments at 45, 47; Nebraska Commission Initial Comments at 9; NESCOE Initial Comments at 54 (citing NOPR, 179 FERC ¶ 61,028 at PP 303, 305); North Carolina Commission and Staff Initial Comments at 15–16; Ohio Commission Federal Advocate Initial Comments at 11; Pacific Northwest State Agencies Initial Comments at 27; PJM States Initial Comments at 9; SoCal Edison Initial Comments at 3; Southeast PIOs Initial Comments at 55 (citing NOPR, 179 FERC ¶ 61,028 at P 303); US Climate Alliance Initial Comments at 2; WIRES Initial Comments at 12.

[2828] Avangrid Initial Comments at 28.

[2829] SoCal Edison Initial Comments at 3.

[2830] PPL Initial Comments at 29.

[2831] NYISO Initial Comments at 49; ISO–NE Initial Comments at 37.

[2832] ISO–NE Initial Comments at 37.

[2833] Mississippi Commission Reply Comments at 5.

[2834] City of New Orleans Council Initial Comments at 9.

[2835] SoCal Edison Initial Comments at 3, 13.

[2836] Southern Initial Comments at 9–10.

Kentucky Commission Chair Chandler asserts that states should not be permanently bound by their agreement on an initial cost allocation method, and that the Commission should clarify that transmission providers should continue to seek agreement from states prior to seeking Commission approval for any change to the cost allocation method filed on compliance.[2837] Similarly, PJM States request that the Commission require transmission providers to show they sought support of retail regulators for subsequent revisions of the initial cost allocation method.[2838] PJM States ask that the Commission also require a regular check-in with retail regulators regarding the appropriateness of any existing cost allocation method.[2839]

1329. Resale Iowa states that it is concerned that large, multi-state transmission projects may increase the number of participants to the point that agreement is difficult to achieve and suggests that multi-state organizations may provide an avenue for conveying state interests to transmission providers and reaching agreements.[2840] DC and MD Offices of People's Counsel support giving state entities a ''defined and expansive role'' in the regional transmission selection and cost allocation processes but argue that this role must be anchored by their ability to timely agree on cost allocation.[2841]

1330. Other commenters offered modified versions of the NOPR proposal. California Commission states that the Commission should require that transmission providers use their FPA section 205 filing rights to submit the *ex post* cost allocation method (and/or combined method) agreed on by states even if the transmission providers in a transmission planning region determine that they will propose an *ex ante* cost allocation method for the Commission's consideration.[2842]

1331. Dominion states that it may be nearly impossible to achieve state consensus in multi-state RTOs/ISOs and that if the states in a transmission planning region are unable to agree on the proper cost allocation method, the transmission providers should be able to file their own proposed cost allocation method.[2843]

1332. Some commenters oppose the proposed requirement to seek agreement. For example, Minnesota State Entities state that the term ''seeking state agreement'' is too vague and may lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans. Minnesota State Entities suggest replacing the term ''seeking state agreement'' with ''take into account'' or ''evaluating and incorporating'' state concerns in the regional cost allocation approaches as regularly happens at MISO and other RTOs/ISOs.[2844] MISO Coops state that the NOPR proposal for a transmission provider to seek agreement with Relevant State Entities is unnecessary and would be inferior to current stakeholder processes, setting up redundant and potentially conflicted processes.[2845]

1333. Kansas Commission questions the necessity of a requirement to seek the agreement of Relevant State Entities within a transmission planning region like SPP, where the SPP Regional State Committee has substantial influence over cost allocation.[2846] PacifiCorp and NV Energy oppose a requirement for transmission providers to seek state agreement on a cost allocation method, contending that such a requirement would add complexity and significant process and time.[2847] NRG states that under the proposal for transmission providers to seek the agreement of Relevant State Entities on cost allocation, customers that ultimately pay the cost of Long-Term Regional Transmission Facilities are left out of the cost allocation process. NRG suggests that the proposal be limited to transmission projects included in regional transmission plans that would not exist but for state public policy, as it is reasonable for states to fill this negotiating role as described in the NOPR.[2848]

1334. MISO TOs contend that MISO and MISO TOs have already afforded opportunities for states to participate in the development of cost allocation methods,[2849] and argue that the NOPR requirements as drafted are unnecessary for the MISO region.[2850] MISO TOs argue that the Commission should find compelling the fact that MISO, MISO TOs, and OMS all support the existing collaborative process for cost allocation in MISO, and request that the Commission not impose changes on this process, but instead afford regional flexibility.[2851]

1335. MISO TOs disagree with commenters that argue that the NOPR provided too much discretion and deference to transmission providers,[2852] or that the Commission should require transmission providers to add a mechanism that ensures compliance with the requirements to include Relevant State Entities in cost allocation.[2853] MISO TOs state that these proposals are contrary to the FPA because they attempt to usurp the statutory rights of transmission providers and point to similar sentiments expressed by the Indicated PJM TOs.[2854]

iv. Requirements Associated With Seeking Agreement of Relevant State Entities

1336. ACEG, ACORE, and NESCOE support the NOPR proposal to require transmission providers to demonstrate their good faith efforts to seek agreement from Relevant State Entities before proposing a Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2855] AEE states that the final order should better define what constitutes ''good faith effort'' to seek agreement on cost allocation from states, including the Commission's minimum expectations concerning the time that transmission providers must allow states to reach agreement, the need to hold meetings, and related topics.[2856] OMS, on the other hand, urges the Commission to not require a formal process in which transmission providers must demonstrate how they sought the agreement of state entities.[2857]

1337. NARUC recommends that the Commission require, at a minimum, that transmission providers: (1)

[2837] Kentucky Commission Chair Chandler Initial Comments at 3.

[2838] PJM States Initial Comments at 10.

[2839] *Id.* at 10–11.

[2840] Resale Iowa Initial Comments at 2, 12.

[2841] DC and MD Offices of People's Counsel Initial Comments at 37.

[2842] California Commission Initial Comments at 55–56.

[2843] Dominion Initial Comments at 48.

[2844] Minnesota State Entities Initial Comments at 7.

[2845] MISO Coops Initial Comments at 4.

[2846] Kansas Commission Initial Comments at 15–16.

[2847] PacifiCorp and NV Energy Initial Comments at 16.

[2848] NRG Initial Comments at 19.

[2849] MISO TOs Initial Comments at 45.

[2850] MISO TOs Reply Comments at 3.

[2851] *Id.* at 9 (citing APS Initial Comments at 10–11; MISO Initial Comments at 55–69; MISO TOs Initial Comments at 41–45; OMS Initial Comments at 10–13).

[2852] *Id.* at 4 (citing California Commission Initial Comments at 51–54).

[2853] *Id.* at 4–5 (citing NARUC Initial Comments at 49; NESCOE Initial Comments at 16–19, 46 (requesting that the Commission either require codification of states' roles for cost allocation of long-term regional transmission facilities in OATTs or require explanation following consultation with states of a different approach)).

[2854] *Id.* at 5, 8 (citing Indicated PJM TOs Initial Comments at 23).

[2855] ACEG Initial Comments at 65; ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NESCOE Initial Comments at 59 (citing NOPR, 179 FERC ¶ 61,028 at P 308).

[2856] AEE Initial Comments at 33–34.

[2857] OMS Initial Comments at 11.

communicate with Relevant State Entities promptly in a manner that is reasonably calculated to be received by the Relevant State Entities and (2) establish a forum for negotiation that enables robust participation from Relevant State Entities and transmission providers.[2858] PacifiCorp and NV Energy urge the Commission to clarify that a transmission provider's obligation under any final order is only to provide state regulators an opportunity to participate in the process of establishing a cost allocation method, should they so choose.[2859] NESCOE asserts that the Commission should require transmission providers to afford Relevant State Entities sufficient time to agree on a cost allocation approach. NESCOE advocates for the Commission to give states six months from the effective date of a final order to agree on a cost allocation method, which NESCOE argues is needed due to the complexity involved.[2860]

1338. Some commenters support the NOPR proposal to provide states flexibility in determining what constitutes agreement among Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.[2861] Alabama Commission contends that the Commission should not establish any specific timeline for negotiation to allow sufficient time for states to reach such agreement.[2862] In contrast, ACEG argues that there must be a firm time frame for any negotiations, because allowing Relevant State Entities more time to reach agreement could unnecessarily delay the process.[2863] Likewise, Pine Gate and PIOs support requiring a firm deadline, arguing that absent such a requirement, a single state or a handful of states could significantly delay transmission development.[2864]

1339. While ACEG supports the NOPR proposal, ACEG cautions that this flexibility should not grant states veto power over the agreement.[2865] Similarly, PJM States argue that the Commission should not require unanimity in determining an initial Long-Term Regional Transmission Cost Allocation Method, and instead, retain the proposal in the NOPR to allow states to determine how they will come to agreement on a Long-Term Regional Transmission Facility cost allocation approach.[2866] New Jersey Commission further asserts that the Commission must ensure that transmission providers cannot unilaterally veto proposals that result from states' negotiations on a cost allocation approach.[2867]

1340. Nebraska Commission asserts that the Commission should allow RTOs/ISOs that have an existing decision-making process that includes state entity participation to continue using it, citing SPP's Regional State Committee and MISO's OMS as well-established processes developed over many years with stakeholder input. Nebraska Commission adds that providing flexibility in this process for transmission providers would be the least disruptive and most useful approach.[2868] Relatedly, ACORE states that where agreements on cost allocation have already been reached with state entities for transmission projects with multiple benefits, the Commission should not require transmission providers to revisit those agreements.[2869]

1341. ISO–NE also supports the Commission's proposal to afford transmission providers flexibility in determining what constitutes state agreement, as well as the process by which they seek agreement from the states. ISO–NE argues that if state agreement cannot be reached, the Commission should allow the transmission planning region to develop a fallback cost allocation method for use in the event that the states agree to move forward with a long-term transmission facility to advance public policy, but do not agree on a cost allocation method. ISO–NE requests that a final order be clear that the OATT will be the means by which the states will communicate the agreed cost allocation method to the transmission provider, but the OATT should not dictate the process by which states engage to achieve consensus.[2870]

1342. Some commenters favor mandating what constitutes agreement among Relevant State Entities. Pine Gate states that the Commission should establish a minimum set of criteria outlining when it will consider there to be such agreement. Pine Gate also asks for clarification as to whether unanimity is necessary for states to reach agreement on a cost allocation method.[2871] Similarly, AEE requests additional guidance on what it means for states to "agree" to cost allocation approaches.[2872] Shell states that an OATT mechanism that clearly delineates the process and timing for state input will facilitate the participation of Relevant States Entities. However, Shell further states, the OATT provision could provide flexibility for stakeholders to identify the relevant agency for each state as the voting entity for cost allocation decisions.[2873]

1343. Acadia Center and CLF assert that the Commission should clarify that states within a given transmission planning region need not unanimously agree on a cost allocation method and can define agreement as necessary when a majority of states in such region approve a cost allocation method for transmission facilities.[2874] Acadia Center and CLF explain that such an approach is consistent with NESCOE's memorandum of understanding in ISO–NE,[2875] and similarly, New England for Offshore Wind argues that the Commission should not require agreement to be unanimous among states in a multi-state transmission planning region.[2876]

1344. PIOs also argue that the Commission should not require that states in a particular transmission planning region unanimously approve an *ex ante* cost allocation method. PIOs assert, rather, that the Commission should allow transmission providers to adopt a cost allocation method that is otherwise just and reasonable with agreement among a majority of states. PIOs state that each RTO/ISO has an organization of states that operates as a committee and that most of these committees require a simple majority vote (for example, the SPP Regional State Committee, OPSI, and OMS) and that the experience with the RTO/ISO regional state committees can be

2858 NARUC Initial Comments at 44.

2859 PacifiCorp and NV Energy Initial Comments at 17.

2860 NESCOE Initial Comments at 60.

2861 *See, e.g.,* ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); Georgia Commission Initial Comments at 8; Massachusetts Attorney General Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NARUC Initial Comments at 47–48 (citing NOPR, 179 FERC ¶ 61,028 at P 306); Nebraska Commission Initial Comments at 10; NESCOE Initial Comments at 58; Pacific Northwest State Agencies Initial Comments at 24–25 (citing NOPR, 179 FERC ¶ 61,028 at PP 309, 318).

2862 Alabama Commission Initial Comments at 9.

2863 ACEG Initial Comments at 64–65.

2864 Pine Gate Initial Comments at 46; PIOs Initial Comments at 69–70.

2865 ACEG Initial Comments at 66.

2866 PJM States Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 304, 319).

2867 New Jersey Commission Initial Comments at 17.

2868 Nebraska Commission Initial Comments at 10.

2869 ACORE Initial Comments at 18 (NOPR, 179 FERC ¶ 61,028 at P 314).

2870 ISO–NE Initial Comments at 37–38.

2871 Pine Gate Initial Comments at 45–46.

2872 AEE Initial Comments at 32–33 (citing NOPR, 179 FERC ¶ 61,028 at P 306).

2873 Shell Initial Comments at 16–17.

2874 Acadia Center and CLF Initial Comments at 30.

2875 *Id.* at 31 (citing Memorandum of Understanding Among ISO–NE, NEPOOL, and NESCOE, at 3, 9 (Nov. 21, 2007), *https://www.iso-ne.com/static-assets/documents/regulatory/part_agree/mou_final.pdf*).

2876 New England for Offshore Wind Initial Comments at 4–5.

extrapolated and applied to the non-RTO/ISO transmission planning regions as well.[2877] Pattern Energy proposes that a reasonable threshold for ''agreement'' would be for one-half of the Relevant State Entities to agree to the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.[2878]

1345. In contrast, Southeast PIOs propose that state agreement should require unanimous acceptance by the states in the relevant transmission planning region. Southeast PIOs state that in the event transmission providers are unable to achieve unanimity, the Commission could presumptively impose the cost allocation mechanism approved by a plurality of the transmission planning region's states.[2879]

v. Outcome if Relevant State Entities Forgo a Role in Determining a Long-Term Regional Transmission Cost Allocation Method

1346. Some commenters support the Commission's proposal that, in the event that states forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, transmission providers must propose a Long-Term Regional Transmission Cost Allocation Method.[2880]

vi. Outcome if Relevant State Entities Fail To Reach Agreement on a Cost Allocation Method

1347. Several commenters agree with the proposal that, in the event that Relevant State Entities fail to reach an agreement on a cost allocation method, transmission providers must file a cost allocation method with the Commission.[2881] NARUC recommends that if Relevant State Entities are unable to reach agreement on cost allocation, the Commission should require transmission providers to file changes to their OATTs that reflect as much consensus as was reached.[2882]

1348. PIOs state that when cost allocation disputes occur, the Commission could use its authority to convene a joint board with affected states to consider issues and make decisions.[2883] PIOs further state that if states cannot agree to an *ex ante* cost allocation method by the compliance deadline for the final order, the Commission should institute a default cost allocation method.[2884]

1349. Similarly, Eversource and Vermont Electric and Vermont Transco state that when Relevant State Entities fail to agree on a cost allocation method, the Commission should establish the Long-Term Regional Transmission Cost Allocation Method.[2885] To improve transparency and certainty, Clean Energy Associations state that the Commission should establish a cost allocation method upfront for situations where ''state concurrence on either an *ex ante* or *ex post* approach'' cannot be reached, submitting that a 90-day period would be reasonable for the Commission to determine a cost allocation method in the absence of state concurrence on either type of approach.[2886]

1350. In contrast, Pacific Northwest State Agencies oppose the Commission establishing a Long-Term Regional Transmission Cost Allocation Method on its own initiative.[2887] NESCOE states that having the transmission provider file a cost allocation method when states cannot agree is preferable to the Commission establishing the cost allocation method. Specifically, NESCOE asserts that a more appropriate role for the Commission is to establish general principles under a final order and evaluate compliance filings made by transmission providers (or subsequent FPA section 205 proposals down the road) for adherence to those principles.[2888]

1351. NESCOE further suggests that if the states cannot reach agreement within the first four months after the effective date of a final order, they should be provided the opportunity to request that the Commission appoint one or more senior staff members to facilitate agreement.[2889]

1352. In contrast, where agreement is not reached in the established timeframe, ACEG states that the Commission should permit transmission providers to explain their good faith efforts undertaken to seek agreement.[2890]

1353. Clean Energy Associations, some state legislators, and some US Senators state that the final order should provide clarity around how disagreements among states or transmission providers regarding cost allocation will be handled.[2891] Clean Energy Associations recommend, and Ørsted agrees, that in the absence of such agreement, the Commission should require cost allocation to track the identified and quantifiable benefits of Long-Term Regional Transmission Facilities.[2892] Senator Schumer supports providing guidance when there is no state agreement on cost allocation to prevent state vetoes of cost allocation methods and to prevent states being incentivized to free ride on transmission planning and avoid costs.[2893]

c. Commission Determination

1354. We decline to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Instead, we modify the NOPR proposal to establish a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.

1355. We adopt the NOPR proposal, with modification, to define Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning

[2877] PIOs Initial Comments at 66–67.

[2878] Pattern Energy Initial Comments at 19.

[2879] Southeast PIOs Initial Comments at 56.

[2880] MISO Initial Comments at 67; NESCOE Initial Comments at 59; Pennsylvania Commission Initial Comments at 13; PIOs Initial Comments at 67.

[2881] ACEG Initial Comments at 64; Entergy Initial Comments at 31; Pacific Northwest State Agencies Initial Comments at 29; PacifiCorp and NV Energy Initial Comments at 16; Pattern Energy Initial Comments at 19; TAPS Initial Comments at 4, 23–24.

[2882] NARUC Initial Comments at 48–49.

[2883] PIOs Initial Comments at 67 (citing 16 U.S.C. 824h; 18 CFR 385.1304).

[2884] *Id.* at 69.

[2885] Eversource Initial Comments at 30 (citing NOPR, 179 FERC ¶ 61,028 at P 310 (citation omitted)); Vermont Electric and Vermont Transco Initial Comments at 4.

[2886] Clean Energy Associations Initial Comments at 36.

[2887] Pacific Northwest State Agencies Initial Comments at 29.

[2888] NESCOE Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

[2889] *Id.* at 60.

[2890] ACEG Initial Comments at 64–65.

[2891] Clean Energy Associations Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 at P 310); Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; US Senators Supplemental Comments at 2.

[2892] Clean Energy Associations Initial Comments at 35–36; Ørsted Initial Comments at 9.

[2893] Senator Schumer Supplemental Comments at 2.

region, including any state entity as may be designated for that purpose by the law of such state.[2894] We modify the definition to add the word ''electric'' before ''utility regulation'' to make clear that Relevant State Entities are those state agencies responsible for *electric* utility regulation, and not other types of utility regulation.

1356. Specifically, with respect to the mechanics of the Engagement Period, we require that transmission providers in each transmission planning region provide notice, such as on its OASIS page or public website, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period. The notice must include contact information for a single point of contact in the transmission planning region that the Relevant State Entities can use to communicate any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement.[2895] Such deadline must be no earlier than the end date of the Engagement Period.

1357. We require transmission providers in each transmission planning region to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period, consistent with NARUC's suggestion.[2896] We require transmission providers to explain on compliance how they complied with the requirement to establish and provide notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as how they complied with the requirement to provide a forum for such negotiation. In response to commenters that argue that their transmission planning regions already have mechanisms for state involvement in regional transmission planning and cost allocation processes,[2897] we note that Relevant State Entities can choose to use existing mechanisms for state involvement in regional transmission planning and cost allocation processes, such as the SPP Regional State Committee and the Organization of MISO States, to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process. However, even where Relevant State Entities indicate to the transmission providers in a transmission planning region that they will use such existing mechanisms as the forum for their negotiations, transmission providers must still demonstrate on compliance that, consistent with the requirements of this final order, they provided notice of the starting and end dates for the six-month time period and posted contact information that Relevant State Entities may use to communicate with transmission providers about their proposed Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process to which Relevant State Entities have agreed, as well as a deadline for communicating such agreement.

1358. As described above, we adopt a six-month time period for the Engagement Period. While the NOPR did not propose a particular time period for the Engagement Period, we believe that the six-month time period that we adopt here balances the need to ensure that Relevant State Entities have sufficient time to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process if they choose to do so, particularly given the complexity that such negotiations may involve, with the need to ensure that an extended Engagement Period does not unduly delay the implementation of the reforms that we adopt in this final order. We appreciate Alabama Commission's concerns about establishing a specific time period for negotiations, but we find that limiting the Engagement Period to six months is necessary to ensure that transmission providers have sufficient time to prepare their compliance filings in advance of the compliance deadlines that we establish in this final order.[2898]

1359. If the Relevant State Entities participating in an Engagement Period agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and provide that Method or Methods and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement, which must be no earlier than the end date of the Engagement Period, the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. We note, however, that the ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.

1360. We do not adopt the NOPR proposal that for each state, a single entity should be designated as the voting or representative entity. In light of the fact that we now require an Engagement Period, rather than mandating that transmission providers seek agreement with Relevant Sate Entities on the relevant cost allocation method or process, we decline to adopt a requirement that a single entity be designated for each state as the voting or representative entity. In addition, we decline to define what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement during the Engagement Period. Instead, we leave such matters, including whether to use existing state processes as a forum for negotiations, as Nebraska Commission advocates,[2899] to the Relevant State Entities participating in the Engagement Period to determine. The requirements that we establish in the final order are that transmission providers must demonstrate on compliance that they established and provided notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as that they provided a forum for such negotiation.

1361. Likewise, we do not agree with commenters, like Pine Gate, that the Commission should establish a minimum set of criteria for a state agreement.[2900] Instead, we find that the criteria for agreement are more appropriately determined by the Relevant State Entities participating in the Engagement Period. Whether agreement should require a majority,[2901] a threshold of one-half of the participating Relevant State Entities,[2902] or unanimity (Southeast PIOs) [2903] is a

[2894] *See* NOPR, 179 FERC ¶ 61,028 at P 304.

[2895] As we discuss above in the Cost Allocation for Long-Term Regional Transmission Facilities section, Relevant State Entities must indicate that they have agreed to any State Agreement Process in order for any such process to be eligible for acceptance by the Commission in compliance with this final order. Consistent with FPA section 205, however, transmission providers have the right to not file a State Agreement Process. *See infra* Filing Rights Under the FPA section for a further discussion. *See also Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002) (finding that the Commission may not require utility owners to give up statutory rights under FPA section 205).

[2896] NARUC Initial Comments at 44.

[2897] *E.g.,* MISO Initial Comments at 61; SPP Initial Comments at 28–30; PJM Initial Comments at 116.

[2898] Alabama Commission Initial Comments at 9.

[2899] Nebraska Commission Initial Comments at 10.

[2900] Pine Gate Initial Comments at 45–46.

[2901] Acadia Center and CLF Initial Comments at 30; PIOs Initial Comments at 66–67.

[2902] Pattern Energy Initial Comments at 19.

[2903] Southeast PIOs Initial Comments at 56.

decision for the Relevant State Entities participating in the Engagement Period. We find that this approach also addresses many of the issues commenters raised relating to the potential difficulties associated with mandating agreement on a Long-Term Regional Transmission Cost Allocation Method(s), including ACEG's concern that requiring agreement could lead to certain states holding a veto power over the agreement.[2904] Moreover, we reiterate that, as discussed in the Cost Allocation Methods for Long-Term Regional Transmission Facilities section above, transmission providers must file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final order; a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities.

1362. We acknowledge commenters' support of the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities regarding the relevant cost allocation method or process to be applied to Long-Term Regional Transmission Facilities, based upon the rationale that states play a critical role in transmission planning, and that facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings.[2905] We find that requiring an Engagement Period provides the same opportunity for robust engagement in the cost allocation process as the NOPR proposal, and thus has the potential to achieve the same important benefits, but will reduce the practical challenges associated with requiring transmission providers to seek the agreement of Relevant State Entities.[2906]

1363. While we agree with commenters regarding the value of an opportunity for state engagement regarding cost allocation, and accordingly adopt the Engagement Period, we do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive.[2907] Transmission providers retain the ultimate responsibility for transmission planning, and, as discussed below, they have FPA section 205 filing rights to propose tariff changes to rates, which the Commission cannot deprive them of via this final order.[2908] The Commission has a statutory responsibility to review such filings to ensure that any proposed cost allocation is just and reasonable and not unduly discriminatory or preferential. Robust state engagement can valuably inform a cost allocation approach, but it cannot supplant these distinct, statutorily defined roles.

1364. We appreciate that certain commenters request to expand or clarify the NOPR's proposed definition of Relevant State Entities to include additional entities, or to otherwise allow the participation of other entities in the Engagement Period. For example, some commenters request that the definition be expanded to include Native American Tribes, self-regulated public power utilities, cooperatives, non-jurisdictional transmission providers, customer interests, state utility consumer advocates, non-traditional state agencies, and local regulatory bodies.[2909] However, we decline to expand participation in the Engagement Period beyond Relevant State Entities. As discussed in the NOPR, ''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.'' [2910] The Commission further stated, and we continue to believe, that ''providing state regulators with a formal opportunity to develop a cost allocation method for [Long-Term Regional Transmission Facilities] selected through Long-Term Regional Transmission Planning 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.'' [2911] For the same reasons, we also do not find it necessary to allow other stakeholders to participate in the Engagement Period, as some commenters advocate.[2912] In response to Nevada Commission's request for additional flexibility in the term Relevant State Entity,[2913] and NESCOE's request to amend the definition to accommodate individual transmission planning regions' particular approaches to cost allocation requirements, we find that the definition of Relevant State Entities, as amended, recognizes the important role of states while providing sufficient regional flexibility for effective Engagement Period participation.[2914]

1365. We acknowledge SERTP Sponsors' concern that determining which Relevant State Entities would be appropriate to participate will be a function of state law,[2915] and, as Pennsylvania Commission points out, a state's legislature could have divided utility regulation and siting authority among different state agencies.[2916] In response to these concerns and Duke's clarification request,[2917] and as we note above, we provide flexibility on how Relevant State Entities reach agreement during the Engagement Period and decline to adopt the requirement that, for each state, a single entity should be designated as the voting or representative entity. We clarify that there may be multiple Relevant State Entities for each state, so long as each Relevant State Entity meets the definition as provided in this final order. As noted above, the definition of Relevant State Entity provides sufficient flexibility for participation in the Engagement Period.

1366. We find that the decision to modify the NOPR proposal, which would have required transmission providers to seek agreement of Relevant State Entities, to instead require transmission providers to establish a six-month Engagement Period largely moots several other reforms proposed in the NOPR. We therefore decline to adopt other proposed reforms that

[2904] ACEG Initial Comments at 66.

[2905] NOPR, 179 FERC ¶ 61,028 at P 301 (footnote omitted); *see, e.g.,* Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; SoCal Edison Initial Comments at 3, 13.

[2906] *See, e.g.,* Minnesota State Entities Initial Comments at 7 (claiming that a requirement to seek agreement could lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans).

[2907] *See, e.g.,* Southern Initial Comments at 9.

[2908] *See, e.g., Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9 (noting that section 205 of the FPA gives utilities the right to file rates and terms for services rendered, and finding that the Commission cannot require that utility owners give up those statutory rights under FPA section 205); *infra* Filing Rights Under the FPA section.

[2909] American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42–43 (citing 16 U.S.C. 796(7), (15)); California Energy Commission Initial Comments at 3; California Municipal Utilities Initial Comments at 16–17; Large Public Power Initial Comments at 41; MISO Coops Initial Comments at 3–4; Northwest and Intermountain Initial Comments at 18; NRECA Initial Comments at 56–57; Six Cities Initial Comments at 10.

[2910] NOPR, 179 FERC ¶ 61,028 at P 297 (footnote omitted).

[2911] *Id.* at P 299.

[2912] *See, e.g.,* Clean Energy Buyers Initial Comments at 29.

[2913] Nevada Commission Initial Comments at 13.

[2914] NESCOE Initial Comments at 57. As discussed below in the Proposals Relating to the Design and Operation of State Agreement Process section, we will permit other participants beyond Relevant State Entities to participate in the State Agreement Process, if agreed to by Relevant State Entities.

[2915] SERTP Sponsors Initial Comments at 28–29.

[2916] Pennsylvania Commission Initial Comments at 15.

[2917] Duke Initial Comments at 38–39.

detailed the requirements associated with transmission providers seeking agreement of Relevant State Entities.

1367. We note that transmission providers' compliance with this final order is not contingent on Relevant State Entities' participation in the Engagement Period. Transmission providers' compliance with this final order is also not contingent on Relevant State Entities reaching an agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. If Relevant State Entities fail to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, transmission providers must still file one or more Long-Term Regional Transmission Cost Allocation Methods in compliance with this final order. We acknowledge commenters' recommendations on action we should take in the event Relevant State Entities fail to reach an agreement. But we decline to convene a joint board of affected states if Relevant State Entities cannot agree, as suggested by PIOs,[2918] and the Commission will not establish a Long-Term Regional Transmission Cost Allocation Method in the event that Relevant State Entities fail to agree, as proposed by Eversource and Vermont Electric and Vermont Transco.[2919] Because this final order requires transmission providers to file a Long-Term Regional Transmission Cost Allocation Method, these additional steps are not necessary to ensure that there will be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1368. Furthermore, we decline to adopt NARUC's request that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Transmission Facilities.[2920] This final order requires that transmission providers establish a one-time Engagement Period for purposes of compliance with this final order; transmission providers may file subsequent changes to their cost allocation methods for Long-Term Regional Transmission Facilities pursuant to their filing rights under FPA section 205, at which point parties may file comments in support of or protests to such filings. We note, however, that some RTOs/ISOs have stakeholder processes that occur prior to making FPA section 205 filings on cost allocation, which could provide an additional opportunity for stakeholders to present their views on a proposed cost allocation method for Long-Term Regional Transmission Facilities. We decline to require future Engagement Periods beyond the initial Engagement Period but note that transmission providers may hold future Engagement Periods if they believe such periods would be beneficial.

3. Proposals Relating to the Design and Operation of State Agreement Processes

a. NOPR Proposal

1369. The Commission preliminarily found that a State Agreement Process by which one or more Relevant State Entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) after they are selected may be a just and reasonable approach to cost allocation for such regional transmission facilities and that the State Agreement Process could apply to all Long-Term Regional Transmission Facilities or only to a subset thereof.[2921]

1370. The Commission proposed to require that if the Relevant State Entities agree on a State Agreement Process, then the transmission providers in each transmission planning region must describe in their OATTs the process by which Relevant State Entities would reach voluntary agreement pursuant to that State Agreement Process regarding the cost allocation for Long-Term Regional Transmission Facilities, including the timeline for such processes. The Commission noted that, for example, the transmission providers in each transmission planning region could specify in their OATTs the procedures by which such voluntary agreements by the Relevant State Entities may be filed with the Commission for consideration under FPA section 205. The Commission proposed to require that such procedures include a process by which Relevant State Entities would agree to funding contributions and the mechanism by which such costs would be allocated (*e.g.,* through a *pro forma* contract).[2922]

b. Comments

i. Support for State Agreement Process

1371. Several commenters generally support the Commission's proposal to permit transmission providers to submit a State Agreement Process as a Long-Term Regional Transmission Cost Allocation Method.[2923] NARUC supports allowing Relevant State Entities to agree to using the State Agreement Process to commit their customers to fund all or a portion of the costs of a Long-Term Regional Transmission Facility as a means of meeting a transmission planning region's selection criteria.[2924]

1372. Mississippi Commission contends that the State Agreement Process will likely promote transmission construction because authority over transmission construction and siting rests with the states.[2925] Mississippi Commission asserts that the State Agreement Process is particularly suited to transmission facilities that promote state policies, noting that Long-Term Regional Transmission Planning should address state laws and utility integrated resource plans that affect the resource mix, but the cost of the transmission facilities needed to address those issues must be borne by the states and utilities whose laws and integrated resource plans require those facilities.[2926] Likewise, Ohio Commission Federal Advocate asserts that a State Agreement Process is a just and reasonable way of allocating costs for public policy projects.[2927] Relatedly, ELCON states that the Commission should emphasize that one state's public policy goals cannot supplant the cost causation principle or be used to impose costs on customers in states that do not have the same goals.[2928]

[2918] PIOs Initial Comments at 67.

[2919] Eversource Initial Comments at 30; Vermont Electric and Vermont Transco Initial Comments at 4.

[2920] NARUC Initial Comments at 49–50.

[2921] NOPR, 179 FERC ¶ 61,028 at P 311.

[2922] *Id.* P 313.

[2923] American Municipal Power Initial Comments at 12; City of New Orleans Initial Comments at 9–10; Entergy Initial Comments at 34–35; Georgia Commission Initial Comments at 8–9; ISO–NE Initial Comments at 37; ITC Initial Comments at 28–32; Louisiana Commission Initial Comments at 33; Mississippi Commission Initial Comments at 6; NARUC Initial Comments at 53–54; NESCOE Initial Comments at 62; North Carolina Commission and Staff Initial Comments at 15–16; Ohio Commission Federal Advocate Initial Comments at 12; Pacific Northwest State Agencies Initial Comments at 27, Pennsylvania Commission Initial Comments at 12–13; PIOs Initial Comments at 64; TAPS Initial Comments at 4–5, 24–26; Resale Iowa Initial Comments at 2, 12; Southern Initial Comments at 9; SERTP Sponsors Initial Comments at 28–29.

[2924] NARUC Initial Comments at 53–54 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

[2925] Mississippi Commission Initial Comments at 22.

[2926] Mississippi Commission Reply Comments at 3, 24 (citing Alabama Commission Initial Comments at 4; Illinois Commission at 4, 7–8).

[2927] Ohio Commission Federal Advocate Initial Comments at 12.

[2928] ELCON Initial Comments at 17–18. Under the cost causation principle, the cost of transmission facilities must be allocated to those who benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. *See*

Continued

1373. Southern also notes that state support for transmission projects is crucial as the states retain primary jurisdiction over transmission siting and certification.[2929] Southern asserts that states should generally be allowed to make transmission project selection and cost allocation decisions pursuant to the State Agreement Process after the planning is performed and specific costs and benefits are identified.[2930] North Carolina Commission and Staff agree that the Commission should allow states to negotiate a cost allocation method after a transmission facility has been selected through Long-Term Regional Transmission Planning.[2931] Similarly, Pennsylvania Commission states that having the State Agreement Process occur after project selection will put planning in the driver's seat, and state negotiation will be centered around a transmission project already selected, which will ensure that project planning and selection run smoothly while not frustrating the fulfillment of a state's need during the state negotiation process.[2932]

1374. Massachusetts Attorney General states that, due to the range and complexity of benefits and the uncertainty associated with using a long transmission planning horizon, permitting states to diverge from *ex ante* cost allocation requirements for particular transmission projects or portfolios of projects may increase the likelihood that those facilities are sited and developed with fewer costly delays and will better ensure just and reasonable rates. Massachusetts Attorney General states that the potential benefits of the State Agreement Process outweigh any concerns about free ridership.[2933] R Street agrees that the proposal for a State Agreement Process could reduce cost allocation and siting disputes, but asserts that states lack the jurisdiction and resources to serve an economic oversight role and thus that state participation is not a substitute for the Commission's economic oversight or for competitive mechanisms.[2934]

1375. NESCOE supports the proposal that the State Agreement Process may apply to all, or a subset of, Long-Term Regional Transmission Facilities. NESCOE contends that, depending on the circumstances, Relevant State Entities may find it unnecessary to have the State Agreement Process apply to all such facilities, and having the flexibility to apply the State Agreement Process to a subset of facilities is a reasonable approach.[2935]

ii. Concerns and Conditions for Support Regarding State Agreement Process

1376. Some commenters qualified their support for the State Agreement Process and/or suggest that the Commission impose conditions upon the process, including those that advocated for flexibility and deference to existing efforts to incorporate state involvement.[2936] US DOE, on behalf of its Federal power marketing administrations, notes that, to the extent that state agreements may involve the participation of Federal power marketing administrations, the process will need to accommodate the jurisdictional implications of the parties involved and that any agreements Federal power marketing administrations execute must be consistent with their statutory authorities.[2937]

1377. Entergy states its understanding that state agreements will not bind retail commissions in exercising other authorities like siting and permitting.[2938] Likewise, Pennsylvania Commission states that any State Agreement Process cannot serve to waive or diminish the state's siting authority over transmission facilities.[2939]

1378. Mississippi Commission states that involving state regulators in cost allocation ensures that one state's policy choices are not imposed on another state's consumers without their consent and that no state should be forced to subsidize implementation of another state's laws and policies.[2940] Likewise, Avangrid states that one state should not be required to fund public policies of another state, as this could derail clean energy efforts and allow states to avoid paying their fair share.[2941] NRG supports a role for states on transmission projects that would not exist but for state public policy.[2942] Virginia Commission Staff avers that state entities should retain the right to assume cost responsibility for transmission projects intended to advance their public policy goals.[2943]

1379. Pennsylvania Commission argues that the terms *ex ante* and *ex post* used in the definitions of the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are vague and that instead, the Commission should include in the definitions that the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are determined either before or after a transmission facility is selected.[2944]

1380. Entergy asserts that the Commission should permit flexibility as to when a State Agreement Process occurs despite the NOPR's reference to the State Agreement Process as ''an *ex post* cost allocation process'' because in some transmission planning regions, it may be appropriate for the State Agreement Process to begin before transmission projects are selected.[2945] Entergy states that any State Agreement Process should be finalized before a portfolio is submitted to the MISO Board of Directors because it will provide certainty to stakeholders as to how costs will be allocated and ensure that the MISO Board of Directors understands how the cost allocation for the portfolio is consistent with the law and capable of withstanding legal challenges.[2946] Relatedly, Mississippi Commission argues that Long-Term Regional Transmission Facilities should not be presented to an RTO/ISO governing board until states have reached agreement on cost allocation.[2947]

1381. Similarly, MISO asserts that the *ex post* nature of the State Agreement Process renders it unsuitable as the sole cost allocation method for Long-Term Regional Transmission Facilities. As such, MISO contends, cost allocation should be available only during a defined time set forth in the OATT, after the approval of the transmission projects, to avoid delays in the competitive transmission development process. MISO further states that failure to conclude the State Agreement Process in that timeframe should result in the transmission provider reverting to its

S.C. Pub. Serv. Auth. v. *FERC,* 762 F.3d at 53 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 586); *see also ICC* v. *FERC I,* 576 F.3d at 476.

[2929] Southern Initial Comments at 9.

[2930] *Id.* at 27.

[2931] North Carolina Commission and Staff Initial Comments at 15–16.

[2932] Pennsylvania Commission Initial Comments at 12–13.

[2933] Massachusetts Attorney General Initial Comments at 19 (citing NOPR, 179 FERC ¶ 61,028 at PP 299, 314).

[2934] R Street Initial Comments at 4, 12.

[2935] NESCOE Initial Comments at 62–63 (citing NOPR, 179 FERC ¶ 61,028 at P 311).

[2936] *Supra* note 2923.

[2937] US DOE Initial Comments at 50.

[2938] Entergy Initial Comments at 29–30 (citing NOPR, 179 FERC ¶ 61,028 at PP 302–309, 314).

[2939] Pennsylvania Commission Initial Comments at 14.

[2940] Mississippi Commission Reply Comments at 2–3.

[2941] Avangrid Initial Comments at 29.

[2942] NRG Initial Comments at 6.

[2943] Virginia Commission Staff Initial Comments at 6.

[2944] Pennsylvania Commission Initial Comments at 14–15.

[2945] Entergy Initial Comments at 34–35.

[2946] *Id.* at 35.

[2947] Mississippi Commission Initial Comments at 25–26.

default Long-Term Regional Transmission Cost Allocation Method. Finally, MISO asks that the Commission clarify that transmission providers can make changes to their competitive transmission development process to accommodate the State Agreement Process.[2948]

1382. DC and MD Offices of People's Counsel recommend that the State Agreement Process afford an opportunity for state entities to participate in transmission project evaluation and selection. They recommend this approach because of regional grid expansions that optimize the interconnection of portfolios of resources that likely result from power supply commitments made in conformity with state policies, and because state entity participation in cost allocation after a transmission project has already been selected may foreclose the consideration of state-specific benefits of grid decarbonization during project evaluation and selection.[2949]

1383. Alabama Commission contends that the Commission should provide for flexibility in the form and substance of any state agreement. Specifically, Alabama Commission explains that under Alabama law, it is unclear how the Alabama Commission would enter into such agreement and that its agreement may instead have to take the form of an order directed to Alabama Power.[2950] SERTP Sponsors also state that the Commission should recognize the importance of flexibility in the development and structure of state agreements, agreeing that a state public service commission may not have authority to enter into binding state agreements. SERTP Sponsors offer that a state agreement for a state public service commission could be an endorsement of a voluntary participant funding agreement among its jurisdictional transmission providers.[2951] Southeast PIOs state that the applicable cost allocation method should account for regional preferences and adds that an *ex ante* method is likely a non-starter in the Southeast, but that a State Agreement Process has real potential.[2952]

1384. Acadia Center and CLF state that voluntary state agreements relating to offshore wind could result in more efficient and cost-effective Long-Term Regional Transmission Facilities but request further clarity on voluntary agreements to assist states in understanding how these agreements allocate costs of transmission upgrades necessary for increased interconnection of renewable projects.[2953] New England Systems states that the Commission should clarify that any State Agreement Process cannot increase the costs paid by a non-consenting transmission customer under an existing cost allocation method.[2954] Pennsylvania Commission seeks clarification that a state that is not a party to a cost allocation agreement developed through the State Agreement Process cannot be required to pay for a selected transmission project.[2955]

1385. Cypress Creek states that the involvement of states in Long-Term Regional Transmission Planning is important but that a State Agreement Process should not be required.[2956] MISO requests that the State Agreement Process be optional so as not to disrupt current frameworks of state collaboration or delay transmission expansion.[2957] MISO further asserts that the proposed cost allocation reforms may undermine existing cost allocation methods and that the Commission should not extend any requirements regarding state involvement to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final order.[2958]

1386. In addition, MISO argues that there should be no requirement for unanimous agreement under the State Agreement Process, particularly if the decision to adopt it rests with Relevant State Entities.[2959] MISO states that some flexibility as to what constitutes agreement of Relevant State Entities may be justified.[2960] While Interwest supports increased state engagement, it argues that state entities should not be authorized to limit regional transmission plans by veto or by using unjust and unreasonable cost allocation principles that are subjective or fail to comprehensively consider benefits.[2961]

1387. Chemistry Council contends that consultation with affected states should not give individual states the power to ''hijack'' the transmission planning process by rejecting necessary investments, withholding consent, or delaying the decision-making process. Chemistry Council asserts that the Commission should clarify that in requiring transmission providers to ''seek agreement'' from states in transmission project selection, it is not suggesting that individual states would have a veto in the process or the ability to unduly influence the timing or outcome of decision-making.[2962]

1388. Evergreen Action encourages the Commission to prohibit one state or stakeholder from vetoing transmission projects or cost allocation decisions. Evergreen Action further states that if consensus is not reached under a State Agreement Process, transmission providers should not extend the time allotted to reach agreement, because this would allow individual parties to delay the approval of needed transmission and remove the time pressure on Relevant State Entities to reach agreement. Evergreen Action avers that instead transmission providers should simply explain that they conducted a good-faith effort to reach agreement.[2963]

1389. SEIA also urges the Commission to limit the opportunity for any single state to veto a transmission line and to use its backstop authority under section 216 of the FPA if parties are unable to reach an agreement and a relevant state authority withholds or denies the siting permit for the transmission facility.[2964] US Climate Alliance agrees that the process should encourage states to engage in good faith discussions to realize common benefits without over-leveraging a single state's power over a regional transmission project.[2965] National Grid suggests that if states cannot agree within a reasonable period on a proposed cost allocation method for a specific set of Long-Term Regional Transmission Facilities, then the transmission providers or developers building those facilities should be required to file a proposed cost allocation method for them.[2966] In contrast, NRG states that without recourse to an *ex ante* cost allocation method, negotiations under the State Agreement Process would be more productive.[2967]

[2948] MISO Initial Comments at 69.

[2949] DC and MD Offices of People's Counsel Initial Comments at 37–38.

[2950] Alabama Commission Initial Comments at 10 n.8.

[2951] SERTP Sponsors Initial Comments at 28–29.

[2952] Southeast PIOs Reply Comments at 22–23 (citing Dominion Initial Comments at 50–52; Duke Initial Comments at 35–37; SERTP Sponsors Initial Comments at 28–29; Southern Initial Comments at 27–28).

[2953] Acadia Center and CLF Initial Comments at 32 & n.93.

[2954] New England Systems Initial Comments at 23.

[2955] Pennsylvania Commission Initial Comments at 12.

[2956] Cypress Creek Reply Comments at 14 (citing Clean Energy Associations Initial Comments at 34).

[2957] MISO Reply Comments at 19.

[2958] MISO Initial Comments at 60, 71.

[2959] *Id.* at 66–67; MISO Reply Comments at 19.

[2960] MISO Initial Comments at 66.

[2961] Interwest Initial Comments at 16.

[2962] Chemistry Council Initial Comments at 7.

[2963] Evergreen Action Initial Comments at 6.

[2964] SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

[2965] US Climate Alliance Initial Comments at 2.

[2966] National Grid Initial Comments at 25–26.

[2967] NRG Initial Comments at 20–21.

1390. California Commission is concerned that the NOPR proposal grants too much deference to transmission providers and will enable them to exercise veto power over state-negotiated cost allocation agreements.[2968] California Municipal Utilities and TANC ask that the Commission require that local regulatory authorities be included in any State Agreement Process, stating that the jurisdictional implications of the NOPR proposal are unclear given that public power entities are not generally subject to the jurisdiction of their respective state commissions.[2969] Mississippi Commission and Northwest and Intermountain support expanding a State Agreement Process to include non-jurisdictional utilities.[2970] California Municipal Utilities further assert that, if any state body is created to examine transmission planning issues, it must include public power entities.[2971] Because the written comment process is not sufficient to facilitate a constructive dialogue, California Municipal Utilities urge the Commission to refrain from adopting any specific proposals from the NOPR until such a dialogue between states and public power can occur.[2972]

1391. Some commenters are concerned about the reliance on voluntary contributions that may occur under a State Agreement Process. Clean Energy Associations states that while *ex post* frameworks that rely on voluntary contributions from states or interconnection customers may be useful in some circumstances, they may not appropriately acknowledge system-wide benefits of high-voltage elements, which under the State Agreement Process could be treated as benefitting only a single state. According to Clean Energy Associations, courts have found such an outcome improper, and this approach is unlikely to yield agreement in practice.[2973] Likewise, Cypress Creek asserts that any *ex post* cost allocation method should acknowledge wide-spread benefits without imposing new restrictions.[2974] AEE contends that the State Agreement Process, and more broadly the requirement to seek agreement of states regarding applicable cost allocation methods, should not substitute for allocating costs to all beneficiaries based on the broad set of benefits that regional transmission investment can provide. AEE states that reliance on voluntary state agreement should allow all states to consider the broad benefits that additional regional transmission facilities provide and the legal obligation to allocate costs commensurate with benefits received.[2975]

1392. DC and MD Offices of People's Counsel suggest that cost allocation should be based on the NOPR's defined benefits to all appropriate beneficiaries, with a further cost allocation to states that opt to submit additional transmission needs. DC and MD Offices of People's Counsel state that this approach would be more expansive than the existing State Agreement Approach in PJM because it would allow for a parallel default allocation of costs to the state entities not opting in, but narrowed to align with the NOPR-listed benefits, and a second round of cost allocation after the participating Relevant State Entities have shared costs aligned with the broader measure of benefits, which would help avoid the free-rider problem.[2976]

1393. Avangrid states that a fair approach to cost allocation under the State Agreement Process could be payments and benefits based on tiers, providing the example that if states A and B have public policies supported by new transmission while state C does not, then only states A and B should pay the cost of public policy benefits while all three states should be responsible for the cost associated with economic and reliability benefits.[2977] Similarly, PIOs assert that under the State Agreement Process, costs identified in Long-Term Regional Transmission Planning should first be allocated to transmission customers as the primary beneficiaries, and then states and/or interconnection customers can voluntarily accept cost allocation for the alternative or expanded transmission projects compared to projects identified in the regional base case plan.[2978]

1394. AEE asks that the Commission provide additional guardrails for the State Agreement Process to ensure that there are not transmission project delays.[2979] According to AEE, the Commission must ensure that excessive reliance on the State Agreement Process does not exacerbate free-ridership problems where states outside of those agreements receive benefits from transmission projects developed under state agreements but are not expected to contribute to the costs.[2980]

1395. Duke argues that any tariff language memorializing the State Agreement Process must specify that the transmission provider ''will not be obligated to accept cost allocation methods proposed by Relevant State Entities.'' [2981] Duke also asks that the Commission clarify that if transmission providers only adopt a State Agreement Process, and that fails, then transmission providers are free to make an FPA section 205 filing to implement an *ex post* cost allocation method.[2982] Further, Duke asks that the Commission clarify that the regulatory text's reference to ''transmission provider'' is ''the entity with the section 205 rights to initiate rate changes, which depending upon the applicable governance and OATT structures, may be the transmission owner, but not the transmission provider.'' [2983]

1396. Some commenters support requiring state involvement in cost allocation. For example, New York Commission and NYSERDA state that state-led cost allocation should be a requirement in any final order and that cost allocation for public policy-driven transmission projects should be subject to state review and approval.[2984] Pacific Northwest State Agencies support requiring transmission providers to have an *ex post* State Agreement Process as an alternative to an *ex ante* cost allocation method.[2985]

iii. Opposition to a State Agreement Process

1397. Some commenters express concern that a State Agreement Process may not be a just and reasonable approach to cost allocation for regional transmission facilities.[2986] R Street contends that states do not represent all beneficiaries who may be assigned costs and, as such, cost allocation predicated on state agreement may be unjust and

[2968] California Commission Initial Comments at 51, 54–55 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

[2969] California Municipal Utilities Initial Comments at 16; TANC Initial Comments at 17.

[2970] Mississippi Commission Reply Comments at 5 (citing MISO Coops Initial Comments at 3–4); Northwest and Intermountain Initial Comments at 18.

[2971] California Municipal Utilities Initial Comments at 4.

[2972] California Municipal Utilities Reply Comments at 10.

[2973] Clean Energy Associations Initial Comments at 35 (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d at 1261).

[2974] Cypress Creek Reply Comments at 14.

[2975] AEE Reply Comments at 15–16.

[2976] DC and MD Offices of People's Counsel Initial Comments at 38–39 (citing *PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024).

[2977] Avangrid Initial Comments at 29–30.

[2978] PIOs Initial Comments at 68 (citing NOPR, 179 FERC ¶ 61,028 at PP 75–76).

[2979] AEE Initial Comments at 33 (citing NOPR, 179 FERC ¶ 61,028 at PP 311–318).

[2980] *Id.*

[2981] Duke Initial Comments at 39–40.

[2982] *Id.* at 3.

[2983] *Id.* at 40 n.77.

[2984] New York Commission and NYSERDA Initial Comments at 12, 14.

[2985] Pacific Northwest State Agencies Initial Comments at 27.

[2986] APPA Initial Comments at 40, 44; MISO Coops Initial Comments at 2; R Street Initial Comments at 12.

unreasonable. R Street states, however, that a state advisory or partial approval mechanism could be structured to give state agreement pivotal influence over cost allocation decisions.[2987]

1398. APPA claims that the proposed State Agreement Process is unworkable and creates significant uncertainty and potential for litigation.[2988] APPA further asserts that providing state regulators with an exclusive role in determining cost allocation methods will not likely result in a broad consensus across stakeholders.[2989] MISO Coops add that it is unjust and unreasonable, arguing that, because cooperatives are often not jurisdictional to a state entity, it is unclear how cooperatives would be represented. Thus, MISO Coops state, the State Agreement Process would reduce the involvement of cooperatives in regional transmission planning processes while granting states authority over entities outside their jurisdiction. MISO Coops further state that the proposed State Agreement Process is unnecessary because the current MISO stakeholder process is superior.[2990] MISO TOs oppose any provision that would mandate a State Agreement Process.[2991]

iv. Requirement To Document State Agreement Process in OATT

1399. Some commenters agree with the NOPR proposal that for any State Agreement Process, transmission providers in each transmission planning region must detail in their OATTs the process by which Relevant State Entities would reach agreement regarding the cost allocation for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, including the timeline for such processes.[2992] NESCOE contends that if the State Agreement Process is chosen by the Relevant State Entities, the details of how the state entities would agree to funding contributions and the mechanisms by which the costs would be allocated should be mostly informed by states and then filed by the transmission provider.[2993] NESCOE suggests that the Commission be open to variations in the State Agreement Process as long as the details of all those variations are filed with the Commission.[2994]

[2987] R Street Initial Comments at 12.

[2988] APPA Initial Comments at 40, 44.

[2989] *Id.* at 43.

[2990] MISO Coops Initial Comments at 2–4.

[2991] MISO TOs Initial Comments at 5, 46.

[2992] Louisiana Commission Initial Comments at 33; NESCOE Initial Comments at 63; SDG&E Initial Comments at 5; TAPS Initial Comments at 24.

[2993] NESCOE Initial Comments at 63.

[2994] NESCOE Reply Comments at 5.

1400. Northwest and Intermountain state that the Commission should review negotiated cost allocation methods.[2995] Likewise, APPA argues that the Commission should require that any state agreement to voluntarily fund transmission facilities must be filed with the Commission for approval, in order to afford parties the opportunity to comment.[2996]

1401. Some commenters disagree that the Commission should require transmission providers in each transmission planning region to detail such processes in their OATTs. For example, OMS argues that it is unnecessary for transmission providers to explicitly define such a process in their OATTs.[2997] Mississippi Commission argues that the Commission should clarify that OATT language describing the process by which states reach agreement should not be prescriptive or limiting and, instead, should provide only a general discussion of a process.[2998]

c. Commission Determination

1402. We adopt the NOPR proposal, with modification, to allow, but not require, transmission providers in each transmission planning region to adopt a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities. We also modify the definition of State Agreement Process to be a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. We note that Relevant State Entities have the option to include the participation of other entities in a State Agreement Process.

1403. As discussed in more detail below, we also adopt the NOPR proposal to require transmission providers that choose to file any State Agreement Process agreed to by Relevant State Entities to describe the State Agreement Process in proposed tariff provisions in their OATTs. The tariff provisions must describe key information on how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the transmission providers; and the circumstances under which, or the information necessary for, transmission providers to file or to consider filing the agreed cost allocation method.[2999]

[2995] Northwest and Intermountain Initial Comments at 18–19.

[2996] APPA Initial Comments at 34–35.

[2997] OMS Initial Comments at 12–13.

[2998] Mississippi Commission Initial Comments at 27–28.

1404. Consistent with the NOPR, we find that a State Agreement Process can be a just and reasonable approach to allocate costs for Long-Term Regional Transmission Facilities. We also find that State Agreement Processes may apply to all Long-Term Regional Transmission Facilities or only to a subset thereof.[3000] We believe that allowing State Agreement Processes will help to address some commenters' request for a stronger state role in the cost allocation of Long-Term Regional Transmission Facilities,[3001] increasing the likelihood that more efficient or cost-effective Long-Term Regional Transmission Facilities that are selected will be developed. However, as discussed in Cost Allocation Methods for Long-Term Regional Transmission Facilities section above, a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities; we also require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final order so that if the State Agreement Process on file fails to result in a Commission-accepted cost allocation method, there will still be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1405. We note that this final order provides significant flexibility to Relevant State Entities with respect to the design and implementation of any State Agreement Process. Such flexibility includes, for example, the opportunity to decide which entities beyond Relevant State Entities will participate in the State Agreement Process, the ability to identify the Long-Term Regional Transmission Facilities to which the State Agreement Process will apply, and how agreement as to a cost allocation method will be reached.

1406. We further expand these flexibilities by modifying the NOPR proposal to clarify that a State Agreement Process can occur either before or no later than six months after

[2999] NOPR, 179 FERC ¶ 61,028 at P 313.

[3000] *Id.* P 311.

[3001] *See, e.g.,* Mississippi Commission Initial Comments at 22; Southern Initial Comments at 9.

a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected. We believe that providing flexibility for a State Agreement Process to occur (and thus for the Relevant State Entities to agree on a cost allocation method) before Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) are selected will increase the likelihood that Regional State Entities support their selection and future development. We note that this flexibility with regard to the timing of a State Agreement Process should accommodate the timing preferences expressed by certain commenters.[3002] However, we also require that any State Agreement Process must be completed, *i.e.,* any resulting cost allocation method must be filed with the Commission, no later than six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities).[3003]

1407. As the Commission has previously noted, agreements outside of the context of Order No. 1000 regional cost allocation methods, such as PJM's State Agreement Approach, can result in cost allocations that are just and reasonable.[3004] We also note that Order No. 1000 allows market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or set of methods, and nothing in this final order would prohibit such voluntary cost sharing arrangements.[3005] Moreover, as the Commission noted in the NOPR, the Commission recently issued a Policy Statement addressing state efforts to develop transmission facilities through voluntary agreements to plan and pay for those facilities, recognizing that such voluntary agreements may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are through the regional transmission planning process.[3006] Further, while we require in this final order that transmission providers have a Long-Term Regional Transmission Cost Allocation Method for selected Long-Term Regional Transmission Facilities, we note that nothing in this final order limits a transmission provider's ability to propose under FPA section 205 any other cost allocation methods in addition to the cost allocation method used to comply with this final order.

1408. In the NOPR, the Commission noted that it has previously expressed concern regarding participant funding, which shares some similarities with State Agreement Processes.[3007] In Order No. 1000, for example, the Commission explained that reliance on participant funding as a regional cost allocation method ''increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development'' and would therefore not comply with the Order No. 1000 regional cost allocation principles.[3008] The Commission declined to allow transmission providers to file participant funding cost allocation approaches as their *ex ante* cost allocation methods for selected regional transmission facilities.[3009] We take a similar approach here: we require transmission providers to include in their OATTs one or more Long-Term Regional Transmission Cost Allocation Methods (*i.e.,* their *ex ante* cost allocation method(s)) that can be used to allocate the costs of selected Long-Term Regional Transmission Facilities. As in Order No. 1000, the Long-Term Regional Transmission Cost Allocation Method cannot be participant funding. We find that requiring a Long-Term Regional Transmission Cost Allocation Method or Methods that will apply to any selected Long-Term Regional Transmission Facility reduces the incentive for project beneficiaries to defer investment.

1409. However, in addition to requiring a Long-Term Regional Transmission Cost Allocation Method, we also provide flexibility to Relevant State Entities to agree to a State Agreement Process, which transmission providers may choose to file as part of their compliance filings. We conclude that allowing such an approach as an option is reasonable despite the Commission's previously-stated concerns with participant funding, because a State Agreement Process is an established process, agreed to in advance and described in transmission providers' OATTs, through which Relevant State Entities agree to a cost allocation method. We find that, for the purposes of Long-Term Regional Transmission Planning, a State Agreement Process will help to facilitate agreement and cooperation among Relevant State Entities. We find that this approach balances the need for the certainty with respect to cost allocation provided by an *ex ante* cost allocation method with the flexibility of allowing for a State Agreement Process-derived cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities). We emphasize, however, that the Commission will still review any cost allocation method that results from a State Agreement Process to ensure that it is just and reasonable and not unduly discriminatory or preferential, and that it allocates costs in a manner that is at least roughly commensurate with estimated benefits.

1410. In the context of Long-Term Regional Transmission Planning, we believe that allowing the use of State Agreement Processes to derive a cost allocation method for selected Long-Term Regional Transmission Facilities will provide states with an opportunity to be more involved in cost allocation for these transmission facilities, leading to an increased likelihood that such facilities are developed. Specifically, the engagement of Relevant State Entities in cost allocation discussions could reduce instances in which a Long-Term Regional Transmission Facility is selected and has an established *ex ante* cost allocation method that applies to it, but ultimately is not developed because it does not receive a necessary state approval.[3010] We also find that a State Agreement Process could provide greater confidence to Relevant State Entities that customers are receiving benefits in a manner that is at least roughly commensurate with the costs they are paying for Long-Term Regional Transmission Facilities.

1411. We acknowledge commenters' concerns that a State Agreement Process could present free-ridership issues.[3011] For example, there could be free-ridership concerns if the Relevant State Entities in certain states agree to be allocated all of the costs for a particular Long-Term Regional Transmission Facility but that facility also benefits other entities in other states that are not similarly allocated costs under the cost allocation method arrived at through the State Agreement Process. However, we

[3002] *See, e.g.,* Pennsylvania Commission Initial Comments at 12–13; Entergy Initial Comments at 35.

[3003] We discuss this duration requirement *infra* at P 1413.

[3004] *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214 at P 142; *PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024 at PP 40–43.

[3005] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 561.

[3006] NOPR, 179 FERC ¶ 61,028 at P 300 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at PP 2, 6).

[3007] *See id.* P 316 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 723).

[3008] *Id.* P 316 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 723). Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. *Id.* P 316 n.519 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486 n.375).

[3009] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 723.

[3010] NOPR, 179 FERC ¶ 61,028 at P 314.

[3011] *See, e.g.,* R Street Initial Comments at 12.

continue to find that allowing a State Agreement Process for Long-Term Regional Transmission Facilities, where agreed to by the Relevant State Entities, appropriately balances free-ridership concerns with the benefit of greater state involvement in determining the cost allocation method for Long-Term Regional Transmission Facilities and the increased likelihood that such facilities will be built.[3012] Additionally, nothing in this final order changes the requirements for all cost allocation methods, including those that result from a State Agreement Process, to allocate costs in a manner that is at least roughly commensurate with estimated benefits, and we believe that Commission review to ensure that cost allocation methods meet that standard will act to prevent free ridership.

1412. As noted above, there is significant commenter support for a State Agreement Process, particularly among state entities. In addition, we believe that many of the concerns expressed about the State Agreement Process proposal appear to be based on a lack of sufficient explanation in the NOPR regarding the implications of the proposal, which we clarify here. Contrary to some comments, we do not require transmission providers to adopt a State Agreement Process; rather, as discussed in the Filing Rights Under the FPA section, transmission providers may choose to file a State Agreement Process for all, or a subset of, Long-Term Regional Transmission Facilities on compliance. Also, we neither impose an obligation on a state or states to agree to a cost allocation method for Long-Term Regional Transmission Facilities, nor do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs.[3013] As we note in the discussion of transmission provider filing rights in the Filing Rights Under the FPA section below, we believe that the applicable statute and precedent require us to preserve the right of transmission providers to file with the Commission their preferred cost allocation method for Long-Term Regional Transmission Facilities to comply with the requirements of this final order.

1413. However, as noted earlier in this section, we establish a deadline of no later than six months after selection of a Long-Term Regional Transmission Facility (or portfolio of such Facilities) by which transmission providers must file any cost allocation method that results from a State Agreement Process. We believe that the State Agreement Process can only be effective if there is a limit on the time to reach agreement before defaulting to the Long-Term Regional Transmission Cost Allocation Method that we require transmission providers include in their OATTs. The lack of such a deadline could cause delay and increase uncertainty regarding selected Long-Term Regional Transmission Facilities. In addition, we agree with some commenters[3014] that a deadline, bolstered by a default Long-Term Regional Transmission Cost Allocation Method, may increase the incentive for Relevant State Entities to reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.

1414. We find that six months is a reasonable period for State Agreement Process deliberations on a cost allocation method because it balances the need for adequate time for negotiations with transmission providers' need for finality in their Long-Term Regional Transmission Planning. While few commenters directly addressed the time period for negotiation under a State Agreement Process for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), many commenters favored this duration for the NOPR proposed reform of a post-selection time period for states to negotiate an alternate cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities) when an *ex ante* cost allocation method would otherwise apply.[3015]

1415. We clarify that, if the Relevant State Entities indicate to transmission providers, as part of the required Engagement Period outlined above, that the Relevant State Entities have agreed to a State Agreement Process, and the transmission providers decide to include that State Agreement Process in their final order compliance filings, then the transmission providers must also detail the State Agreement Process in proposed tariff provisions to their OATTs. The tariff provisions must describe how agreement would be reached regarding the cost allocation method for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, which also necessarily requires that it be clear which entities can participate in the specific State Agreement Process.[3016] This requirement is in furtherance of one of the goals of the final order, which is to allow a greater role for states in establishing a cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities).

1416. As noted above, after the required initial Engagement Period, a State Agreement Process could include other entities beyond Relevant State Entities, and those entities would need to be enumerated in the State Agreement Process included in the OATT. Transmission providers must first specify in their OATTs a description of how such voluntary agreements by the Relevant State Entities may be shared with transmission providers, as well as whether the transmission providers voluntarily agree to undertake an obligation to file the agreed-upon cost allocation method with the Commission for consideration under FPA section 205 (in other words, whether the transmission providers voluntarily waive their FPA section 205 filing rights such that they commit themselves to file with the Commission any cost allocation method that results from the State Agreement Process). Their OATT provisions must, at a minimum, also include the event triggering the beginning of the State Agreement Process, the duration of the State Agreement Process (not to exceed six months after selection), and a description of the Long-Term Regional Transmission Facilities to which the process applies. Further, the State Agreement Process procedures outlined in transmission providers' OATTs must set forth the manner in which a transmission provider would file a section 205 filing to seek Commission acceptance of a cost allocation method resulting from a State Agreement Process. We note that Relevant State Entities that participate in a State Agreement Process may need to provide relevant information to transmission

[3012] NOPR, 179 FERC ¶ 61,028 at P 317.

[3013] For example, transmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.

[3014] *See* Evergreen Action Initial Comments at 6; MISO Initial Comments at 67–68; National Grid Initial Comments at 25–26.

[3015] California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial Comments at 34–35; NARUC Initial Comments at 52–53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28.

[3016] NOPR, 179 FERC ¶ 61,028 at P 313.

providers to enable them to demonstrate that any cost allocation method that results from a State Agreement Process is just, reasonable, and not unduly discriminatory or preferential, and allocates cost in a manner that is at least roughly commensurate with estimated benefits.

1417. We do not agree with the commenters that recommend against memorializing and filing cost allocation methods resulting from a State Agreement Process with the Commission.[3017] To fulfill the Commission's statutory obligations, any cost allocation method that results from a State Agreement Process must be filed for review by the Commission and determined to be just, reasonable, and not unduly discriminatory or preferential. In addition, we believe that transparency regarding such cost allocation methods and the opportunity for stakeholders, particularly those that will be responsible for paying the costs of Long-Term Regional Transmission Facilities, to comment on them are an important safeguard to ensure that costs are allocated in a manner that is at least roughly commensurate with estimated benefits.

1418. We will not specify the level of agreement among Relevant State Entities or other entities that is necessary before a transmission provider files a cost allocation method derived from a State Agreement Process. As a state-led process, we believe that Relevant State Entities should have the ability to determine this important facet of their State Agreement Process. To this end, we decline to require unanimity or a set minimum threshold for agreement of Relevant State Entities to participate in the State Agreement Process.

1419. Some commenters request that the Commission clarify whether and to what extent a cost allocation method that results from a State Agreement Process can impose costs on entities that do not agree to that cost allocation method. However, we decline to prejudge any State Agreement Process or any cost allocation method that may result from a State Agreement Process. Any cost allocation method for a Long-Term Regional Transmission Facility (or portfolio of such Facilities) that results from a State Agreement Process must be filed with the Commission pursuant to FPA section 205, and the Commission must make a finding as to whether that cost allocation method is just, reasonable, and not unduly discriminatory or preferential. And, as noted above, we reiterate that all cost allocation methods, including those resulting from a State Agreement Process, must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[3018] Parties are free to raise any concerns about the costs that they may be allocated under a State Agreement Process-derived cost allocation method if and when that method is filed with the Commission.[3019]

1420. MISO asks that the final order make clear that transmission providers can make necessary changes to the competitive transmission developer selection process to accommodate the State Agreement Process.[3020] We clarify that the Commission will review any proposed changes to transmission providers' competitive transmission developer selection processes to accommodate State Agreement Processes as part of their compliance filings to this final order.

1421. With respect to California Municipal Utilities' and TANC's requests that the Commission require that local regulatory authorities be included in any State Agreement Process, the Mississippi Commission's statement that it would support expanding the State Agreement Approach to include non-jurisdictional utilities, we do not proscribe in this final order that the State Agreement Processes include other entities beyond Relevant State Entities. However, as noted above, Relevant State Entities have the option to include the participation of other entities in a State Agreement Process. Finally, with respect to US DOE's comments related to the jurisdictional implications of Federal power marketing administrations participating in State Agreement Processes, we do not establish any specific requirements for how State Agreement Processes will be designed. To the extent that a Federal power marketing administration does participate in such a process, it may advocate that such process facilitates its participation in a manner that is consistent with its statutory authority.[3021]

4. Filing Rights Under the FPA

a. Comments

1422. A number of commenters express concerns that a requirement to seek agreement from Relevant State Entities regarding a cost allocation approach could conflict with transmission providers' filing rights under the FPA.[3022] For example, AEP contends that in at least one region where AEP operates, such a requirement would deprive transmission owners of their exclusive right to file tariffs governing the rates and terms of their transmission service under section 205 of the FPA. AEP states that in *Atlantic City Electric Company* v. *FERC,* the D.C. Circuit, held that ''[w]hen FERC attempts to deprive the utilities of their rights to initiate rate design changes with respect to services provided by their own assets, FERC has exceeded its jurisdiction.'' [3023]

1423. Similarly, Dominion reminds the Commission that the transmission provider has FPA section 205 rights, and that those rights cannot be ceded to the state through this proceeding.[3024] National Grid asserts that the FPA gives transmission providers the ability to make section 205 filings on cost allocation, and that the State Agreement Process should be based on transmission providers voluntarily affording a role for states.[3025]

1424. APPA contends that requiring public utilities to file rate terms dictated by non-public utility entities raises jurisdictional issues under the FPA. APPA does not believe it is reasonable to provide to state regulators exclusive authority over the proposed cost allocation method in the absence of agreement by relevant stakeholders, and argues that if the Commission requires public utilities to file cost allocation methods agreed to by Relevant State Entities, public power utilities should be considered Relevant State Entities have a formal voting role in agreeing on

[3017] Mississippi Commission Initial Comments at 27–28; OMS Initial Comments at 12–13.

[3018] *See ICC* v. *FERC I,* 576 F.3d at 477; *ICC* v. *FERC III,* 756 F.3d at 564.

[3019] *E.g.,* New England Systems Initial Comments at 23; Pennsylvania Commission Initial Comments at 12; Mississippi Commission Reply Comments at 3.

[3020] MISO Initial Comments at 68–70.

[3021] US DOE Initial Comments at 50.

[3022] AEP Initial Comments at 6, 36 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9–11 (''[T]his Court, among others, has stressed that the power to initiate rate changes rests with the utility and cannot be appropriated by FERC in the absence of a finding that the existing rate was unlawful.''); *Atl. City Elec. Co.* v. *FERC,* 329 F.3d 856, 858–59 (D.C. Cir. 2003) (per curiam)); MISO Initial Comments at 63–64 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9–11); MISO TOs Initial Comments at 37, 39–40 (citing 16 U.S.C. 824d; *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9–11; *Sw. Power Pool, Inc.,* 132 FERC ¶ 61,042, at P 107 (2010); *Mass. Dep't of Pub. Utils.* v. *FERC,* 729 F.2d 886, 887–88 (1st Cir. 1984)); PPL Initial Comments at 25 & n.66 (''[T]he *Atlantic City* case makes clear that the transmission owners are able to make Section 205 filings regarding cost allocation without additional conditions and the Commission cannot compel the transmission owners to cede these rights.'').

[3023] AEP Initial Comments at 36 (quoting *Atl. City Elec. Co.* v. *FERC,* 329 F.3d at 859); *accord* MISO Initial Comments at 63; MISO TOs Initial Comments at 40; PPL Initial Comments at 25 n.66.

[3024] Dominion Initial Comments at 48–49 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1; *Atl. City Elec. Co.* v. *FERC,* 329 F.3d 856).

[3025] National Grid Initial Comments at 25.

the cost allocation method(s) for Long-Term Regional Transmission Facilities.[3026] Six Cities and Large Public Power argue that the Commission's proposal is an unlawful delegation of the Commission's exclusive statutory authority over rates under the FPA.[3027]

1425. Some commenters seek clarification on the Commission's proposal. MISO and Vistra request that the Commission clarify that nothing in the final order should be read to override or diminish the filing rights held, jointly and/or individually, by the RTOs/ISOs and their transmission owning members.[3028] Indicated PJM TOs argue that, while *seeking* the agreement of Relevant State Entities is appropriate, the Commission does not have the authority to require that transmission providers *obtain* their agreement.[3029] Similarly, WIRES states that the Commission should clarify that transmission providers are only required to *seek* agreement of Relevant State Entities and that they are not required to achieve such agreement.[3030] Duke asserts that the Commission should clarify and revise the proposed State Agreement Process to ensure that it does not conflict with transmission providers' FPA section 205 rights to initiate rate changes.[3031]

1426. PJM States propose that if retail regulators reach an agreement on cost allocation, transmission providers should be required to file it for consideration under section 205 of the FPA.[3032] PJM States recommend that if the transmission providers in a transmission planning region prefer a different cost allocation method, they can file their preferred alternative while also presenting the method agreed on by the Relevant State Entities.[3033] PJM States add that these proposals should be ''balanced'' and explain how the retail regulators' preferences were considered.[3034] Similarly, NESCOE states that in cases of disagreement between state entities and transmission providers, they would prefer that the transmission providers file a state-preferred cost allocation method alongside their own preferred method, arguing that such an approach would respect the FPA section 205 rights that public utilities hold.[3035] Similarly, New Jersey Commission recommends that in the event that the transmission provider disagrees with the approach desired by states, the Commission should require them to submit the states' approach as well as their own in their section 205 filing. New Jersey Commission proposes that the Commission would then decide which OATT filing to accept.[3036]

1427. Entergy contends that the proposal is within the Commission's authority because the Commission's proposal allows transmission providers to retain their filing rights consistent with *Atlantic City.* Entergy argues that the NOPR proposal does not conflict with *Atlantic City* because it would only establish a process where states are consulted on designing a cost allocation method, and that transmission providers still must make a cost allocation filing, even if there is no agreement.[3037]

b. Commission Determination

1428. As a threshold matter, we note that the Commission is acting pursuant to FPA section 206 in this final order. Under FPA section 206, the Commission has determined that existing regional transmission planning and cost allocation requirements are unjust, unreasonable, unduly discriminatory or preferential, and thus has both the authority and responsibility to establish a just and reasonable replacement rate consistent with the final order's requirements.[3038]

1429. As to commenters' FPA section 205 arguments, we find that our directives in this final order regarding the development of a State Agreement Process and any cost allocation methods to which the Relevant State Entities agree pursuant to that process do not alter existing FPA section 205 filing rights.[3039] Specifically, we clarify that, after the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings.[3040] Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method and not file a State Agreement Process or other *ex ante* cost allocation method to which Relevant State Entities agreed. In addition, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs. In the same vein, we decline to require, as PJM States, NESCOE, and New Jersey Commission suggest, that transmission providers file two cost allocation methods—the transmission providers' preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities—if the transmission providers disagree with a proposed cost allocation method to which the Relevant State Entities agree.[3041] Entities that oppose or prefer a different cost allocation method than the transmission providers' preferred cost allocation method can provide their comments if and when such cost allocation method is filed with the Commission.

1430. We further clarify that unless voluntarily waived, a transmission provider retains its FPA section 205 filing rights to submit an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities at any time,[3042] consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO. In response

[3026] APPA Initial Comments at 42–45.

[3027] Large Public Power Initial Comments at 37–38 (citing *City of Tacoma* v. *FERC,* 331 F.3d 106, 115 (D.C. Cir. 2002) (finding that the Commission unlawfully delegated its responsibility to assess annual charges imposed under the FPA against hydroelectric utilities licenses to other Federal agencies) (additional citations omitted)); Six Cities Initial Comments at 8–9 (citing 16 U.S.C. 824d(a), 824e; *Nantahala Power & Light Co.* v. *Thornburg,* 476 U.S. 953, 965–66 (1986); *EPSA,* 577 U.S. at 277).

[3028] MISO Initial Comments at 64; Vistra Initial Comments at 29–30.

[3029] Indicated PJM TOs Initial Comments at 20 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 10–11).

[3030] WIRES Initial Comments at 12 (citing 16 U.S.C. 824d; *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9–11; *Atl. City Elec. Co.* v. *FERC,* 329 F.3d at 858–59).

[3031] Duke Initial Comments at 39 (citing *Atl. City Elec. Co.* v. *FERC,* 329 F.3d at 858–59).

[3032] PJM States Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 303).

[3033] *Id.* at 10.

[3034] *Id.* at 10.

[3035] NESCOE Reply Comments at 4.

[3036] New Jersey Commission Initial Comments at 17–18.

[3037] Entergy Initial Comments at 31–33 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 11).

[3038] 16 U.S.C. 824e(a) (''[T]he *Commission* shall determine the just and reasonable . . . practice . . . to be thereafter observed and in force, and shall fix the same by order.'' (emphasis added)).

[3039] *See* Dominion Initial Comments at 48–49 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1; *Atl. City Elec. Co.* v. *FERC,* 329 F.3d 856).

[3040] We note that the filing must include a Long-Term Regional Transmission Cost Allocation Method (*i.e.,* an *ex ante* cost allocation method).

[3041] PJM States Initial Comments at 10; NESCOE Reply Comments at 4; New Jersey Commission Initial Comments at 17–18.

[3042] *See Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9–11; *Atl. City Elec. Co.* v. *FERC,* 329 F.3d at 858–859.

to MISO and Vistra,[3043] we also clarify that nothing in this final order should be read to override or diminish the filing rights held, jointly or individually, by RTOs/ISOs and their transmission owning members.

1431. In response to commenters arguing that the NOPR proposal to require transmission providers to seek agreement of Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof would interfere with transmission providers' filing rights under FPA section 205,[3044] those concerns are moot, as we decline to adopt this NOPR proposal, as discussed above. We reiterate that transmission providers retain their right to decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file in compliance with this final order after the Engagement Period.

5. Time Period and Related Issues in the Long-Term Regional Transmission Planning Cost Allocation Processes for State-Negotiated Alternate Cost Allocation Method

a. NOPR Proposal

1432. In the NOPR, the Commission proposed to require transmission providers to detail in their OATTs a process to provide a state or states (in multi-state transmission planning regions) with a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method (*i.e.,* Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply. During this time period, if a state or all states within the transmission planning region in which the selected regional transmission facility will be located unanimously agree on an alternate cost allocation method, the transmission provider may elect to file that method with the Commission for consideration under FPA section 205. The Commission explained that the transmission provider may elect to file an alternate cost allocation method because doing so increases the likelihood that relevant stakeholders perceive the cost allocation as fair and that the needed regional transmission facilities will actually be constructed.[3045]

1433. If the relevant state or states cannot agree on an alternate cost allocation method memorialized in writing within the specified timeframe after a transmission developer's transmission facility is selected through Long-Term Regional Transmission Planning (*e.g.,* 90 days), the Commission proposed that then the transmission developer would be entitled to use any *ex ante* Long-Term Regional Transmission Cost Allocation Method that would otherwise apply for that Long-Term Regional Transmission Facility.[3046]

1434. In particular, the Commission proposed to require that the OATT provisions that describe the state-negotiated alternate cost allocation method include when this time period will occur, what its duration will be, and an affirmation that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect. Under this proposal, when filed, the Commission would evaluate the alternate cost allocation method to ensure that it is just and reasonable and allocates costs in a manner that is at least roughly commensurate with estimated benefits. If the Commission rejects a state-negotiated alternate cost allocation method, the transmission developer of the Long-Term Regional Transmission Facility would be entitled to use the applicable *ex ante* regional cost allocation method that would have applied to it in the absence of the proposed alternative cost allocation method.[3047] The Commission proposed to prescribe a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.[3048]

1435. Finally, the Commission sought comment on whether to establish 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.[3049]

b. Comments

1436. Several commenters support the Commission's proposal to require transmission providers to detail in their OATTs a process to provide a state or states with a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method (*i.e.,* Long-Term Regional Transmission Cost Allocation Method).[3050] NESCOE, Pennsylvania Commission, and PJM States support a requirement for transmission providers to detail in their OATT provisions that describe the state-negotiated cost allocation method.[3051] Clean Energy Buyers, Dominion, and PIOs agree that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect.[3052]

1437. PJM and Nebraska Commission support the proposal to require a time period for state-negotiated alternate cost allocation with suggested modifications. Nebraska Commission states that a process that builds consensus is important for contentious issues such as cost allocation and suggests adoption of a model similar to SPP's Regional State Committee, which it contends has a proven track record for achieving consensus among stakeholders.[3053] PJM recommends that the Commission provide clear direction as to the circumstances under which a process for states to negotiate an alternate cost allocation method would be appropriate. PJM also proposes that states seeking a state-negotiated alternate cost allocation method should be required to explain why the *ex ante* cost allocation method is not appropriate for the identified transmission facility or facilities.[3054]

1438. PJM States disagree, arguing that there is no proposed requirement that retail regulators show why an *ex ante* approach is inappropriate before agreeing to and advocating for an alternate. PJM States further assert that allowing states to agree on an alternate cost allocation approach after seeing what transmission projects are selected may be beneficial since states will have more information on specific projects.[3055]

[3043] MISO Initial Comments at 64; Vistra Initial Comments at 29–30.

[3044] AEP Initial Comments at 36; APPA Initial Comments at 42; Dominion Initial Comments at 48–49; MISO Initial Comments at 63–64; MISO TOs Initial Comments at 37, 39–40; MISO TOs Reply Comments at 5–7; PPL Initial Comments at 25 & n.66.

[3045] NOPR, 179 FERC ¶ 61,028 at P 319.

[3046] *Id.* P 320.

[3047] *Id.* P 322.

[3048] *Id.* P 323.

[3049] *Id.* P 324.

[3050] Entergy Initial Comments at 29–30; Nebraska Commission Initial Comments at 9; New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18–19; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

[3051] NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12–13.

[3052] Clean Energy Buyers Initial Comments at 29–30; Dominion Initial Comments at 52; PIOs Initial Comments at 71.

[3053] Nebraska Commission Initial Comments at 9.

[3054] PJM Initial Comments at 117.

[3055] PJM States Reply Comments at 6.

1439. Some commenters seek clarification on the NOPR proposal. Pennsylvania Commission explains that because this negotiation would occur after transmission facility selection, it is an *ex post* ''State Agreement Process.'' As such, Pennsylvania Commission contends, it could create confusion if the Commission does not clarify that different rules apply to the 90-day ''renegotiation'' process.[3056] Similarly, MISO states that it is not clear whether the proposed requirements are intended as an alternative to the State Agreement Process or to define how the State Agreement Process would be implemented.[3057]

1440. Some commenters oppose a requirement to provide a time period for a state or states to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected in the regional transmission plan that is different than any *ex ante* regional cost allocation method (*i.e.,* Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply.[3058] Dominion and Idaho Power argue that the Commission should permit regional flexibility as to whether to adopt such a time period.[3059] Idaho Power further contends that the Commission's transmission planning processes are not the primary barriers to transmission development; instead, Federal permitting and siting processes and coordination with stakeholders are greater barriers.[3060]

1441. MISO recommends that rather than requiring the specific process and *ex post* opportunities for states to negotiate an alternate cost allocation method, the Commission should identify the opportunity for state involvement in the development of cost allocation and leave the details for that involvement to each transmission planning region.[3061] Pennsylvania Commission states that it does not view the time period for state-negotiated alternate cost allocation as a principal negotiation method for cost allocation and asserts that more appropriate processes are the proposed State Agreement Process or PJM's existing State Agreement Approach.[3062]

1442. Dominion supports allowing but not requiring that *ex ante* processes be coupled with an option for states to propose an alternate method, stating that the process for establishing an alternative cost allocation method could become cumbersome as the NOPR proposes to require it to comply with the six Order No. 1000 regional cost allocation principles.[3063] Exelon recommends allowing states the opportunity to propose an alternative cost allocation method to the *ex ante* method after transmission project selection, but states that FPA section 205 rights holders should be able to accept, modify, or reject the proposed alternative cost allocation method. Exelon claims that this approach would respect the legal rights of transmission owners, pointing to PJM's State Agreement Approach as an example.[3064] NESCOE urges the Commission to reject Exelon's request that transmission providers be free to accept or reject cost allocation methods proposed by state entities.[3065]

i. Permissive Right of Transmission Provider To File Alternate Cost Allocation Method With the Commission Upon Unanimous State Agreement

1443. NARUC and NESCOE argue that if states unanimously agree on an alternate cost allocation method, then the transmission provider should be obligated to file it.[3066] NARUC states that the transmission provider may also file the cost allocation method that would otherwise apply if it concludes that the negotiated cost allocation method does not comply with the six Order No. 1000 regional cost allocation principles or is otherwise deficient. NARUC contends that this approach would not violate the transmission providers' FPA section 205 filing rights.[3067] Similarly, NESCOE asserts that the Commission should allow the transmission provider to file its preferred approach, but also require that the transmission provider file the state-negotiated alternate cost allocation method, an approach that could be modeled after existing provisions in NYISO and SPP.[3068]

1444. NESCOE also requests that the Commission clarify whether unanimity means that each opting-in state has agreed to fund the Long-Term Regional Transmission Facility or that all the states in the transmission planning region have agreed that a subset of states will fund the Long-Term Regional Transmission Facility.[3069] NESCOE further requests that the Commission clarify how it intends to reconcile the unanimous agreement requirement in this proposal with the other NOPR proposal that gives states the ability to choose the definition of state agreement for purposes of a cost allocation method and where the NOPR expressed a willingness to abide by the bylaws of an individual regional state committee, which may not define agreement as full unanimity.[3070]

1445. Indiana Commission expresses concern that the requirement to obtain unanimous state approval regarding an *ex post* cost allocation process might prove unworkable. Indiana Commission argues that it may be unrealistic to expect that states can reach unanimity on something as contentious as cost allocation. Moreover, Indiana Commission is concerned that states may use the requirement for unanimous agreement to leverage their vote and to gain ground in other areas of contention.[3071]

1446. PIOs seek clarification on the intent behind the NOPR language 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.'' [3072] Similarly, Pennsylvania Commission and PJM States request clarification regarding whether transmission providers could choose not to file an alternative cost allocation method to which the states in a transmission planning region have unanimously agreed.[3073] Pennsylvania Commission asserts that it sees no reason why a transmission provider should be able to override the unanimous agreement of affected states.[3074]

1447. In addition, PJM States recommend that to address the inability for states to voice their cost allocation concerns, the Commission should

[3056] Pennsylvania Commission Initial Comments at 15.

[3057] MISO Initial Comments at 71.

[3058] Dominion Initial Comments at 51; Idaho Power Initial Comments at 10–11; PPL Initial Comments at 27.

[3059] Dominion Initial Comments at 51; Idaho Power Initial Comments at 10–11.

[3060] Idaho Power Initial Comments at 11 (noting National Environmental Policy Act review and siting decisions with the Bureau of Land Management as examples of Federal permitting and siting processes).

[3061] MISO Initial Comments at 71.

[3062] Pennsylvania Commission Initial Comments at 16.

[3063] Dominion Initial Comments at 51.

[3064] Exelon Initial Comments at 26–27.

[3065] NESCOE Reply Comments at 3–4.

[3066] NARUC Initial Comments at 53; NESCOE Initial Comments at 68.

[3067] NARUC Initial Comments at 53.

[3068] NESCOE Initial Comments at 68–70.

[3069] *Id.* at 10, 67–68.

[3070] *Id.* at 68 (citing NOPR, 179 FERC ¶ 61,028 at P 306 & n.512).

[3071] Indiana Commission Initial Comments at 5.

[3072] PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

[3073] Pennsylvania Commission Initial Comments at 16–17; PJM States Reply Comments at 6.

[3074] Pennsylvania Commission Initial Comments at 17.

consider how it can afford retail regulators greater participation status in the FPA section 205 filing process.[3075] Further, PJM States note that other regional states committees have varying processes, including the ability to request that a transmission provider file a cost allocation method on their behalf.[3076]

ii. Duration for the Time Period for State-Negotiated Cost Allocation

1448. A few commenters agree with the Commission's proposal to require a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.[3077] For example, New England for Offshore Wind states that it is essential that deadlines are imposed to prevent delays caused by disagreements over cost allocation.[3078] PIOs assert that the 90-day time period should begin when the transmission project or portfolio of projects is selected.[3079]

1449. Many commenters, however, argue that the 90-day time period is too short. For example, NARUC, National Grid, and Southern contend that 90 days may be insufficient time for the states in large, multi-state transmission planning regions to negotiate a cost allocation method.[3080] Similarly, NRG argues that the Commission might consider alternative timelines for multi-state collaboration versus where there is a single state entity responsible for the cost allocation.[3081] US Chamber of Commerce contends that the 90-day timeline for state-negotiated cost allocation agreements is unreasonably tight and may undermine the potential for agreement.[3082]

1450. Several commenters, including state commissions, propose longer time periods. For example, California Commission, Kentucky Commission Chair Chandler, Louisiana Commission, NARUC, NRG, and Pacific Northwest State Agencies propose at least six months (180 days) as a more appropriate time period for state negotiation.[3083] California Commission and Louisiana Commission request that states should be provided with the opportunity to request extensions if they fail to agree on a cost allocation method after six months (180 days).[3084] OMS recommends that the Commission establish periodic reporting requirements for transmission providers during the 90-day period with an option to extend the deliberations for good cause.[3085]

1451. Several other commenters contend that it should be left to the transmission planning regions, with input from states, to determine the appropriate time period.[3086] For example, Dominion states that the Commission should not dictate any particular timetable and should instead evaluate proposals on a case-by-case basis.[3087] Similarly, Nevada Commission proposes that the Commission require relevant state agencies to be involved in the process as early as possible, but to provide no less than 120 days to allow for appropriate notice and review of any state-negotiated agreement.[3088] Exelon, Indiana Commission, and SERTP Sponsors recommend allowing flexibility in determining the appropriate time period to reflect regional differences.[3089] Idaho Power agrees but cautions that any process should not extend the length of transmission planning processes or development.[3090] Pennsylvania Commission also supports flexibility in determining the appropriate time period given that this process is new and there is little knowledge and experience with respect to how it will function in practice.[3091]

1452. NESCOE and PJM States assert that NYISO's process referenced by the Commission can last longer than the 90-day time period for state-negotiated cost allocation proposed in the NOPR.[3092] Further, NESCOE emphasizes that the NYISO process involves only one state entity, whereas other transmission planning regions have multiple states. Thus, NESCOE and PJM States argue, the Commission should allow transmission planning regions to determine what time period is appropriate.[3093]

1453. A few other commenters contend that state negotiation on an alternate cost allocation method should not be limited by any time period. For example, PPL asserts that limiting the timeframe merely lowers the chance of state agreement, and thus the prospects for the underlying transmission project to be constructed.[3094] Southern states that the Commission should allow transmission planning regions to develop a process that has state support.[3095] Similarly, Xcel contends that transmission planning regions should have as much time as needed to negotiate and identify cost allocation methods.[3096]

iii. Other Issues

1454. NESCOE, Northwest and Intermountain, PJM, and SEIA agree with the proposal that if states cannot unanimously agree on an alternate cost allocation method within the specified timeframe, then the transmission developer would be entitled to use the cost allocation method that would otherwise apply for that Long-Term Regional Transmission Facility.[3097] In contrast, NRG recommends that in the case where states do not agree, the Commission could either require the transmission provider to make a filing or subject rival state filings to ''jump ball'' treatment. NRG contends that either of these approaches would encourage comity and resolution of states' differences.[3098]

1455. MISO and PPL oppose establishing 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. MISO states that

[3075] PJM States Reply Comments at 6–7.

[3076] *Id.* at 7.

[3077] New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

[3078] New England for Offshore Wind Initial Comments at 5.

[3079] PIOs Initial Comments at 70.

[3080] NARUC Initial Comments at 52–53; National Grid Initial Comments at 24–25; Southern Initial Comments at 7–8.

[3081] NRG Initial Comments at 21.

[3082] US Chamber of Commerce Initial Comments at 10.

[3083] California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial Comments at 34–35; NARUC Initial Comments at 52–53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28.

[3084] California Commission Initial Comments at 56; Louisiana Commission Initial Comments at 35.

[3085] OMS Initial Comments at 13.

[3086] Dominion Initial Comments at 51–52; Exelon Initial Comments at 28–29; Indiana Commission Initial Comments at 5–6; National Grid Initial Comments at 24–25; NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12–13; SERTP Sponsors Initial Comments at 15.

[3087] Dominion Initial Comments at 51–52.

[3088] Nevada Commission Initial Comments at 13–14.

[3089] Exelon Initial Comments at 28–29; Indiana Commission Initial Comments at 5–6; SERTP Sponsors Initial Comments at 15.

[3090] Idaho Power Initial Comments at 10–11.

[3091] Pennsylvania Commission Initial Comments at 16.

[3092] NESCOE Initial Comments at 70–71 (citing NOPR, 179 FERC ¶ 61,028 at P 323); PJM States Initial Comments at 12–13 (citing *N.Y. Indep. Sys. Operator, Inc.,* 151 FERC ¶ 61,040, at PP 119–121 (2015)).

[3093] NESCOE Initial Comments at 71; PJM States Initial Comments at 12–13.

[3094] PPL Initial Comments at 27.

[3095] Southern Initial Comments at 7–8.

[3096] Xcel Initial Comments at 11–12.

[3097] NESCOE Initial Comments at 70; Northwest and Intermountain Initial Comments at 19; PJM Initial Comments at 117–118; SEIA Initial Comments at 24.

[3098] NRG Initial Comments at 21.

there is no evidence in the record of this proceeding to support extending the state involvement proposed in the NOPR to existing near-term transmission planning processes.[3099] PPL argues that departures from an *ex ante* cost allocation method would lead to uncertainty, delay, and costly litigation.[3100]

c. Commission Determination

1456. We decline to adopt the NOPR proposal to require transmission providers to provide a time period after selection of Long-Term Regional Transmission Facilities for states to negotiate an alternate cost allocation that is different than any *ex ante* regional cost allocation method that would otherwise apply. We find that requiring a time period after selection for states to negotiate an alternate *ex post* cost allocation method is largely duplicative given our decision above to allow the use of a State Agreement Process before or after the selection of a Long-Term Regional Transmission Facility (or a portfolio of such Facilities). Furthermore, having two separate processes that serve similar functions could add unnecessary complexity and create confusion in the cost allocation process.[3101] Relevant State Entities will have an opportunity to provide input on and to potentially agree to a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process as part of the Engagement Period that we require transmission providers to establish. We are also concerned that the burden associated with the NOPR proposal would have been significant, as it would have created a requirement to allow for such negotiations for all Long-Term Regional Transmission Facilities.

1457. Because we are declining to require that transmission providers establish a time period after selection of Long-Term Regional Transmission Facilities to allow states to negotiate an alternate *ex post* cost allocation method, we need not address the comments on the duration of such a time period and the requests for clarification by MISO, Pennsylvania Commission, PIOs, and PJM States.[3102]

B. Long-Term Regional Transmission Facility Cost Allocation Compliance With the Existing Six Order No. 1000 Regional Cost Allocation Principles

1. NOPR Proposal

1458. The Commission proposed to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities comply with the existing six Order No. 1000 regional cost allocation principles.[3103] The six regional transmission cost allocation principles adopted in Order No. 1000 are: (1) the costs of selected transmission facilities 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 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.[3104]

2. Comments

a. General Proposal

1459. Some commenters agree with the Commission's proposal that any Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities must comply with the existing six Order No. 1000 regional cost allocation principles.[3105] APPA requests that the Commission clarify that it is not requiring changes to existing Commission-approved Order No. 1000 regional cost allocation principles.[3106]

1460. New Jersey Commission supports requiring that any negotiated cost allocation method, whether *ex ante* or *ex post,* comply with the Order No. 1000 regional cost allocation principles, except for Principle 4.[3107] New Jersey Commission opines that requiring that cost allocation methods be consistent with the beneficiary-pays principle is particularly necessary in a State Agreement Process to avoid potential free ridership.[3108]

1461. Industrial Customers argue that, regardless of the cost allocation method that is chosen, the Commission should explicitly state that the cost causation principle must apply, as compliance with Order No. 1000 may not ensure compliance with cost causation principles on its own.[3109] Large Public Power argues that the Commission must hew closely to the first two principles governing cost allocation articulated in Order No. 1000: (1) that costs must be allocated in a way that is roughly commensurate with benefits; and (2) that there will be no involuntary allocation of costs to non-beneficiaries.[3110] Pine Gate asserts that transmission providers must be required to propose cost allocation methods that comport with the well-established ''roughly commensurate'' principle.[3111] City of New Orleans Council and Ohio Commission Federal Advocate state that cost allocation must adhere to cost causation and beneficiary-pays principles.[3112]

1462. OMS states that it developed its own principles through a committee of regulators focused on cost allocation for long-range transmission projects in response to the NOPR, which include: (1) costs of new transmission projects should be allocated to cost causers and beneficiaries in a manner roughly commensurate with the costs caused and benefits of those projects; (2) cost

[3099] MISO Initial Comments at 71.

[3100] PPL Initial Comments at 27–28.

[3101] *See, e.g.,* MISO Initial Comments at 71 (seeking clarification as to whether the proposed time period for states to negotiate cost allocation is an alternative to the State Agreement Process); Pennsylvania Commission Initial Comments at 16 (stating that it does not view the proposed time period as the principal method for negotiating cost allocation and that the more appropriate process is the proposed State Agreement Process).

[3102] MISO Initial Comments at 71; Pennsylvania Commission Initial Comments at 15; PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319); PJM States Reply Comments at 6.

[3103] NOPR, 179 FERC ¶ 61,028 at P 302.

[3104] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[3105] APPA Initial Comments at 40; Dominion Initial Comments at 45; Kentucky Commission Chair Chandler Initial Comments at 3; NESCOE Initial Comments at 56; NRECA Initial Comments at 56; Ohio Consumers Initial Comments at 12–13.

[3106] APPA Initial Comments at 5.

[3107] New Jersey Commission Initial Comments at 18 (citing New Jersey Commission ANOPR Comments at 7–8 (explaining why it opposes Principle 4's policy of allowing beneficiaries in other transmission planning regions to evade all cost allocation for transmission projects that provide them with substantial benefits)).

[3108] *Id.*

[3109] Industrial Customers Initial Comments at 23–24.

[3110] Large Public Power Initial Comments at 29.

[3111] Pine Gate Initial Comments at 42–44.

[3112] City of New Orleans Council Initial Comments at 10; Ohio Commission Federal Advocate Initial Comments at 14.

allocation should be as granular and accurate as possible such that benefit-cost analysis uses metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking; (3) costs should not be allocated to parties that receive negligible or negative benefits; and (4) generators and load each can be considered cost causers, beneficiaries, or both and should be allocated costs accordingly.[3113] Louisiana Commission supports OMS' position on benefit metrics as articulated in OMS' second principle.[3114] OMS highlights that regional flexibility must be preserved, pointing to MISO's Targeted Market Efficiency Projects process as an example of a process that did not strictly comply with Order No. 1000 but was effective and widely supported.[3115]

1463. Ohio Consumers argue that the Commission should espouse three fundamental principles when considering the benefits and cost allocations associated with any Long-Term Regional Transmission Facilities: (1) costs should be allocated to those who caused the costs to be incurred; (2) subsidies are bad for competitive markets, because they result in noncompetitive outcomes and inaccurate price signals; and (3) consumers should not be charged until transmission projects are found to be used and useful.[3116] Also, Ohio Consumers assert, cost allocations to consumers should adhere to the Commission's current ratemaking standards in PJM.[3117]

1464. PIOs assert that the Commission should require that transmission providers demonstrate on compliance that the cost allocation method complies with the beneficiary-pays principle by considering all quantifiable benefits.[3118] ELCON states that cost allocation proposals must comply with the cost causation principle ''by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' ELCON remains concerned that, in an effort to reach public policy goals, costs will be socialized among all consumers without consideration of the cost causers, and states that cost allocation must evaluate the drivers of the specific transmission need and the party that caused the need for the additional transmission.[3119] Utah Division of Public Utilities asks that when states or other stakeholders disagree on the cost allocation method due to differing renewable goals, the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of the proposed transmission projects are due to state policies.[3120]

1465. West Virginia Commission states that it supports retention of the cost-causation principles in Order No. 1000, noting that the Order No. 1000 cost allocation principles are grounded in the beneficiary-pays principle that the costs of transmission facilities should be allocated commensurate with the benefits of those facilities. However, West Virginia Commission contends that the beneficiary-pays principle cannot and should not be applied on a presumptive regional basis when new transmission is identified as needed to accommodate one or more states' public policy decisions.[3121] West Virginia Commission states that longstanding legal precedent on cost causation and ratemaking principles require that rates remain just and reasonable, that customers pay for transmission upgrades based upon their roughly commensurate benefits, and that new generators, or the willing and voluntary benefactors of new generators, pay the costs for the interconnection-related network upgrades if such upgrades would not be needed but for the new generators.[3122] West Virginia Commission contends that to adopt a cost allocation that requires any non-volunteering state to pay costs caused by another state's public policies would depart from years of Commission precedent and would be unjust and unreasonable.[3123]

1466. Vermont Electric and Vermont Transco encourage the Commission to ensure that any cost allocation approach ensures that the benefits of transmission facilities are roughly commensurate with the costs thereof for both small rural states and larger, more populated states. Vermont Electric and Vermont Transco argue that the final order should reflect equitable principles in accordance with which the significant investments made by Vermont prior to the issuance of the final order are taken into account in cost allocation processes.[3124] MISO states that the final order should not preclude applying different cost allocation methods to transmission projects of the same type, noting that Order No. 2000 contemplated ''the potential for different cost allocation methodologies'' as RTO/ISO footprints grew.[3125]

b. Comments Specific to a State Agreement Process

1467. Certain commenters discuss the interaction between the Order No. 1000 regional cost allocation principles and any cost allocation methods resulting from the State Agreement Process. Pennsylvania Commission supports the proposed requirement while also contending that the Commission should defer to unanimous agreement by affected states.[3126] Avangrid argues that the Commission should relax this requirement and defer to the balance achieved via state agreement.[3127] Mississippi Commission argues that the proposed requirement is unnecessary because the State Agreement Process will result in voluntary assumption of costs.[3128] Likewise, PacifiCorp and NV Energy argue that the Order No. 1000 regional cost allocation principles should not apply to the State Agreement Process because there will be no involuntary cost allocation given that states have already agreed. They further contend that beneficiary analyses and minimum cost-benefit ratios will foreclose state-favored cost allocation solutions.[3129] PacifiCorp and NV Energy argue that agreeing to cost allocation will be a difficult task for states, and the Commission should not further dictate the type of agreement.[3130]

1468. PJM States ask the Commission not to preclude or limit the availability of the PJM State Agreement Approach, which they assert is not required to comply with the Order No. 1000

[3113] OMS Initial Comments at 12.

[3114] Louisiana Commission Reply Comments at 10.

[3115] OMS Initial Comments at 13.

[3116] Ohio Consumers Initial Comments at 6–7, 12–14.

[3117] *Id.* at 1.

[3118] PIOs Initial Comments at 68.

[3119] ELCON Initial Comments at 15.

[3120] Utah Division of Public Utilities Initial Comments at 9–10.

[3121] West Virginia Commission Reply Comments at 3; West Virginia Commission Supplemental Comments at 3–4.

[3122] West Virginia Commission Reply Comments at 6 (citing *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992); *ICC* v. *FERC I,* 576 F.3d at 477; *ISO New England, Inc.,* 115 FERC ¶ 61,145, at P 13 (2006), *aff'd, TransCanada Power Mktg. Ltd.* v. *FERC,* 811 F.3d 1 (D.C. Cir. 2015); *El Paso Elec. Co.* v. *FERC,* 832 F.3d 495, 499–500 & n.10 (5th Cir. 2016); *Midcontinent Indep. Sys. Operator, Inc.,* 159 FERC ¶ 63,016, at P 138 (2017), *aff'd,* 164 FERC ¶ 61,194 (2018); Order No. 1000, 136 FERC ¶ 61,051 at P 622); West Virginia Commission Supplemental Comments at 5–6.

[3123] West Virginia Commission Reply Comments at 6–7.

[3124] Vermont Electric and Vermont Transco Initial Comments at 3–4.

[3125] MISO Reply Comments at 17–19.

[3126] Pennsylvania Commission Initial Comments at 13.

[3127] Avangrid Initial Comments at 30.

[3128] Mississippi Commission Initial Comments at 25.

[3129] PacifiCorp and NV Energy Initial Comments at 17.

[3130] *Id.*

regional cost allocation principles.[3131] Similarly, Exelon notes that the Commission has indicated that voluntary state cost allocation agreements need not comply with Order No. 1000.[3132] Therefore, Exelon asks the Commission to clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation.[3133]

3. Commission Determination

1469. We adopt the NOPR proposal, with modification, to require Long-Term Regional Transmission Cost Allocation Methods to comply with five of the six existing Order No. 1000 regional cost allocation principles. Specifically, we require transmission providers in each transmission planning region to demonstrate on compliance with this final order that any Long-Term Regional Transmission Cost Allocation Methods, that they propose that Relevant State Entities have *not* indicated that they agree to, comply with Order No. 1000 regional cost allocation principles (1) through (5). However, we do not require transmission providers to demonstrate that any Long-Term Regional Transmission Cost Allocation Methods that they propose complies with Order No. 1000 regional cost allocation principle (6), and, as a result, unlike under Order No. 1000, transmission providers cannot adopt different Long-Term Regional Transmission Cost allocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.

1470. However, as discussed further below, we do not adopt the NOPR proposal to require compliance with the Order No. 1000 regional cost allocation principles in two situations. First, we do not require a Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles *if* Relevant State Entities indicate that they agreed to that method as part of the Engagement Period. Second, we do not require a cost allocation method resulting from a State Agreement Process to comply with the Order No. 1000 regional cost allocation principles.

1471. The first five Order No. 1000 regional transmission cost allocation principles are: (1) the costs of selected transmission facilities 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; [3134] (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; [3135] (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; [3136] (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; [3137] and (5) the method for determining benefits and identifying beneficiaries must be transparent.[3138]

1472. We find that Order No. 1000 regional cost allocation principles (1) through (5) remain relevant for *ex ante* cost allocation methods for Long-Term Regional Transmission Facilities that transmission providers propose on compliance but with which Relevant State Entities have *not* indicated their agreement. In Order No. 1000, regarding regional cost allocation principle (1), the Commission stated that ''[r]equiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts.'' [3139] Since making that statement, the Commission and the courts have only further strengthened this connection between beneficiaries-pay cost allocation and the cost causation principle.[3140] Similarly, principle (2) continues to ''express[ ] a central tenet of cost causation'' and is ''thus essential to proper cost allocation.'' [3141]

1473. Concerning regional cost allocation principle (3), as noted in Order No. 1000, transmission providers may choose to establish such a threshold to mitigate against uncertainty in the measurement of benefits and costs, and this principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan.[3142] As to regional cost allocation principle (4), this final order maintains the close link established by Order No. 1000 between regional transmission planning and cost allocation to the region being planned for.[3143] Further, we find, similar to the Commission's findings in Order No. 1000, that removing regional cost allocation principle (4) would be tantamount to interconnection-wide transmission planning because unilateral allocation of costs from one transmission planning region to another would require stakeholders to actively monitor regional transmission planning processes in numerous other regions.[3144] Lastly, we find, similar to Order No. 1000, that regional cost allocation principle (5) will ensure that Long-Term Regional Transmission Cost Allocation Methods are just and reasonable and not unduly discriminatory or preferential, will help aid in development and construction of new transmission, and may avoid contentious litigation or prolonged debate among stakeholders.[3145]

1474. In contrast to the first five regional cost allocation principles, Order No. 1000 regional cost allocation principle (6) is inconsistent with Long-Term Regional Transmission Planning as directed in this final order. Order No. 1000 Regional cost allocation principle (6) provides that there may be different regional cost allocation methods for different types of transmission facilities in the regional transmission plan but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance.[3146] As we explain below, however, transmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types. Permitting such project-type-limited Long-Term Regional Transmission Cost Allocation Methods would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final order. Accordingly, in declining to require that Long-Term Regional

[3131] PJM States Initial Comments at 11–12 (citing *PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214 at P 142).

[3132] Exelon Initial Comments at 27–28 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at P 4).

[3133] Exelon Initial Comments at 27–28 (citing *PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214).

[3134] Order No. 1000, 136 FERC ¶ 61,051 at P 622.

[3135] *Id.* P 637.

[3136] *Id.* P 646.

[3137] *Id.* P 657.

[3138] *Id.* P 668.

[3139] *Id.* P 623. *See also id.* P 586 & n.453 (citing *ICC* v. *FERC I,* 576 F.3d at 476–77; *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1369 (D.C. Cir. 2004); *Sithe/Indep. Power Partners, L.P.* v. *FERC,* 285 F.3d 1, 5 (D.C. Cir. 2002)).

[3140] *Long Island Power Auth.* v. *FERC,* 27 F.4th 705, 713–14 (D.C. Cir. 2022); *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d at 1261–63.

[3141] Order No. 1000, 136 FERC ¶ 61,051 at P 637.

[3142] *Id.* PP 647–648.

[3143] *Id.* P 660. *See also S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 87–88.

[3144] Order No. 1000, 136 FERC ¶ 61,051 at P 660. *See also S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 87–88.

[3145] Order No. 1000, 136 FERC ¶ 61,051 at P 669.

[3146] *Id.* P 685.

Transmission Cost Allocation Methods comply with Order No. 1000 regional cost allocation principle (6), consistent with the request of some commenters,[3147] we find that reliability, economic, or public policy transmission facility types reflect a more siloed approach to regional transmission planning that is misaligned with our Long-Term Regional Transmission Planning reforms and would likely lead to the allocation of the costs of Long-Term Regional Transmission Facilities in a manner that is not at least roughly commensurate with estimated benefits.

1475. We clarify that this final order does not preclude the adoption of multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection, *i.e.,* is an *ex ante* cost allocation method, and does not allocate costs by project type. We find that knowing the applicability of a Long-Term Regional Transmission Cost Allocation Method in advance is inherent to the definition of, and one of the primary reasons for, requiring transmission providers to include an *ex ante* cost allocation method in their OATTs. As such, transmission providers that choose to propose more than one Long-Term Regional Transmission Cost Allocation Method on compliance are required to make clear in their OATTs which Long-Term Regional Transmission Cost Allocation Method applies to which Long-Term Regional Transmission Facilities (*e.g.,* cost allocation methods that apply to Long-Term Regional Transmission Facilities above a certain voltage threshold or to Long-Term Regional Transmission Facilities located within a specific portion of a transmission planning region's footprint).[3148] However, we emphasize that any Long-Term Regional Transmission Cost Allocation Method that transmission providers propose, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, must comply with Order No. 1000 regional cost allocation principles (1) through (5) and the other requirements of this final order.

1476. Regarding cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and asked transmission providers to file after the Engagement Period, the Commission has previously found that ''Order No. 1000 allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s).'' [3149] Additionally, where transmission providers have proposed cost allocation methods corresponding to such voluntary arrangements, the Commission has held that it need not find that those cost allocation methods comply with Order No. 1000.[3150] Consistent with this precedent, we find that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file also qualify as voluntary alternative cost sharing arrangements and, accordingly, we decline to require those methods to adhere to the six Order No. 1000 regional cost allocation principles. However, those methods must still comply with the cost causation principle and any other legal requirements for cost allocation.

1477. We decline to adopt the NOPR proposal that required adherence to the six Order No. 1000 regional cost allocation principles because cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to are likely to facilitate agreement over development of such Long-Term Regional Transmission Facilities by, for example, making the Relevant State Entities more confident that customers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities and by reducing the likelihood that selected Long-Term Regional Transmission Facilities cannot be constructed because they do not receive necessary state regulatory approvals. Affording additional flexibility for these methods may encourage their use, which would facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. However, as described in the next section, we note that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to must be just and reasonable and not unduly discriminatory or preferential and must allocate costs in a manner that is at least roughly commensurate with estimated benefits.[3151]

1478. ELCON and West Virginia Commission express concern that the NOPR's proposals for cost allocation methods, including requiring compliance with the six Order No. 1000 regional cost allocation principles, might not sufficiently recognize specific Public Policy Requirements as driving the needs for specific Long-Term Regional Transmission Facilities and, therefore, allow cost allocation methods that contradict precedent on cost causation. Similarly, Utah Division of Public Utilities asks that the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of Long-Term Regional Transmission Facilities are due to state policies when states or other stakeholders disagree on the cost allocation method due to differing renewable goals. We believe these concerns are misplaced and no further requirements are necessary. First, while state laws, regulations, and goals make up some of the drivers of Long-Term Transmission Needs, they do not comprise the entirety of those needs, as described in the Development of Long-Term Scenarios section of this final order. Second, as described below, all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs to transmission customers in a manner that is at least roughly commensurate with their estimated benefits. Third, for Long-Term Regional Transmission Cost Allocation Methods, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, compliance with five of the Order No. 1000 regional cost allocation principles further safeguards against cost causation concerns; notably, principles (1) and (2) require that benefits received are at least roughly commensurate with costs paid and that costs may not be involuntarily allocated

[3147] Massachusetts Attorney General Initial Comments at 15, 21; Ørsted Initial Comments at 9.

[3148] We believe that this finding should address MISO's request that the final order not preclude applying different cost allocation methods to projects of the same type.

[3149] *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at P 3 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 561, 724; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 728–729).

[3150] *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214 at PP 142–143, *order on reh'g and compliance,* 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.,* 143 FERC ¶ 61,150 at P 121; *Consol. Edison Co. of N.Y., Inc.,* 180 FERC ¶ 61,106, at PP 48–50 (2022).

[3151] *See, e.g., PPL Elec. Utils. Corp.,* 181 FERC ¶ 61,178 at P 33.

to those that do not benefit, respectively. Further, Order No. 1000 regional cost allocation principle (5), as well as the requirements in this final order to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities, ensures sufficient transparency for stakeholders to understand how the costs of selected Long-Term Regional Transmission Facilities will be allocated to transmission customers in relation to the benefits that they are forecasted to provide. Lastly, for cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities have agreed to and asked transmission providers to file, we believe that states will have an opportunity to come to consensus on cost allocation methods that they perceive as allocating costs in a manner that is at least roughly commensurate with estimated benefits.

1479. Regarding Vermont Electric and Vermont Transco's concern regarding possible discrepancies between benefits received by small rural states and larger, more populated states, we believe that our requirement that all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs in a manner that is at least roughly commensurate with estimated benefits addresses this concern. Regarding OMS's, Louisiana Commission's, and Ohio Consumers' requests that the Commission adopt certain cost allocation principles distinct from the six Order No. 1000 regional cost allocation principles, the Commission did not propose adoption of any additional principles or that the six Order No. 1000 regional cost allocation principles be substituted for others. Accordingly, we find these requests beyond the scope of this final order. Additionally, in response to Exelon's request that the Commission clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation,[3152] we clarify that any State Agreement Process that the Commission accepts in compliance with this final order will apply to only Long-Term Regional Transmission Facilities, while any existing voluntary state cost allocation processes that the Commission has previously accepted apply to other transmission facilities and, thus, are unaltered by this final order.

[3152] Exelon Initial Comments at 27–28.

C. Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities

1. NOPR Proposal

1480. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers must explain the rationale for using the benefits identified.[3153] The Commission also requested comment on whether the Commission should require that transmission providers account for the full list of benefits, as described in the Evaluation of the Benefits of Regional Transmission Facilities section above, in Long-Term Regional Transmission Planning, or whether no change to the benefits currently used in existing regional transmission planning processes is needed.[3154]

1481. The Commission also proposed, for purposes of cost allocation, to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.[3155]

2. Comments

a. Agree With Proposal

1482. Some commenters agree with the NOPR proposal.[3156] NESCOE contends that it is critical that costs as well as benefits be clearly identified in connection with project evaluation.[3157]

1483. Many commenters supporting the proposal emphasize the importance of flexibility and the lack of a proposed requirement in the NOPR to require that specific benefits be accounted for in cost allocation.[3158] Dominion opposes making the NOPR's listed benefits mandatory for cost allocation because identifying and measuring them would be difficult and lead to disputes and litigation that would add to the costs, borne by consumers, of transmission development.[3159] NYISO states that considering the list of benefits in the NOPR in cost allocation would introduce significant complexity and create a burdensome and perhaps infeasible process.[3160] Xcel states that not all benefits need to be studied given that such study can be costly and add little value, and that the analysis of future benefits should balance uncertainties to ensure that it is not too speculative.[3161]

1484. Pacific Northwest Utilities and SERTP Sponsors argue that many of the NOPR's proposed benefits would work only in RTO/ISO transmission planning regions and are not appropriate in non-RTO/ISO regions.[3162] Pacific Northwest Utilities state that several of the benefits listed in the NOPR do not benefit transmission providers and argue that—in non-RTO/ISO transmission planning regions, like NorthernGrid, where there is neither a single independent transmission system operator nor any single independent transmission provider through which to affect transmission rate impacts due to cost allocation—costs allocated to transmission providers must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities.[3163] California Municipal Utilities argue that requiring consideration of the list of benefits in the NOPR would not reflect the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and consumer protection against speculative

[3153] NOPR, 179 FERC ¶ 61,028 at P 326.

[3154] *Id.* P 327.

[3155] *Id.* P 228.

[3156] Avangrid Initial Comments at 29; California Energy Commission Initial Comments at 3; Idaho Power Initial Comments at 11; ITC Initial Comments at 30; NESCOE Initial Comments at 72; Northwest and Intermountain Initial Comments at 18–19.

[3157] NESCOE Initial Comments at 72.

[3158] APPA Initial Comments at 46; Dominion Initial Comments at 45–46; Dominion Reply Comments at 6, 9; Exelon Initial Comments at 29–30 (citing NOPR, 179 FERC ¶ 61,028 at P 312 & n.516; *Midwest ISO Transmission Owners,* 373 F.3d at 1369); Louisiana Commission Initial Comments at 35–36; NARUC Initial Comments at 38; National Grid Initial Comments at 26–27; NYISO Initial Comments at 51–52; Pacific Northwest Utilities Initial Comments at 8–9; PPL Initial Comments at 28; SERTP Sponsors Initial Comments at 30–31; Southern Initial Comments at 27; Xcel Initial Comments at 12.

[3159] Dominion Reply Comments at 6–7.

[3160] NYISO Initial Comments at 52.

[3161] Xcel Initial Comments at 12.

[3162] Pacific Northwest Utilities Initial Comments at 8–10; SERTP Sponsors Initial Comments at 29–30.

[3163] Pacific Northwest Utilities Initial Comments at 9–10.

projects.[3164] Louisiana Commission states that transmission providers and retail regulators should be allowed to develop and agree on an appropriate set of metrics to be used for cost allocation.[3165]

1485. APPA argues that regional flexibility should include allowing transmission providers to demonstrate on compliance that the benefits that they use to allocate the costs of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.[3166] National Grid asserts that flexibility avoids the risk of a static list of benefits becoming outdated, citing as an example the growing numbers of distributed resources in New England driving the need for transmission-level upgrades in New England. National Grid claims that more granular (state-specific or even direct assignment) cost allocation is appropriate for such upgrades.[3167]

1486. City of New Orleans Council, OMS, Louisiana Commission, and Michigan Commission argue that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2, which states that ''[c]ost allocation should be as granular and accurate as possible. Benefit-cost analysis should use metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking.'' [3168] NARUC similarly asserts that transmission benefits must be verifiable and quantifiable to justify allocating costs to ratepayers.[3169] Likewise, Idaho Power, Pacific Northwest Utilities, and West Virginia Commission state that benefits must be quantifiable and justified, arguing that many benefits in the NOPR proposal would be difficult to quantify, a difficulty, Idaho Power and Pacific Northwest Utilities argue, exacerbated by the proposed 20-year transmission planning horizon.[3170]

1487. West Virginia Commission argues that use of these benefits allows for unfettered discretion by transmission providers to adopt cost allocation methods that do not meet the cost causation principle.[3171]

1488. Southern states that a cost allocation premised on an overly broad, non-quantifiable construction of benefits would likely exceed the Commission's authority because there must be a correlation between the charges proposed and the expected benefits, as articulated by the courts.[3172] Southern states that the Commission must apply the roughly commensurate standard by determining whether the benefits to the intended beneficiaries are quantifiable and spread evenly across a transmission planning region. Otherwise, Southern states, the Commission must compile a record based on substantial evidence to support the proposed allocation of costs.[3173] Dominion similarly cautions that assignment of costs requires more than generalized articulation of benefits and that the list of benefits in the NOPR are broadly defined and generalized.[3174]

1489. Ohio Consumers state that the Commission should base the benefits attributable to Long-Term Regional Transmission Planning on the electrons to be delivered from generating facilities. Ohio Consumers point out that state consumer advocates disagree as to which benefits should be considered in cost allocation.[3175] Ohio Consumers argue that adopting a broad definition of benefits that includes state decarbonization plans and socialization of some portion of the associated costs across a transmission planning region would violate the Order No. 1000 regional cost allocation principles and the cost causation principle.[3176]

1490. Pennsylvania Commission takes no position on requiring certain benefits to be accounted for in cost allocation, but states that the need for objective, well-defined, and measurable benefits applies not only to transmission planning but also to cost allocation, noting that it is important that customers who pay the costs allocated to them agree that they are paying for real and appreciable benefits.[3177]

b. Requests To Reflect the Full Breadth of Benefits in Cost Allocation Methods While Maintaining Flexibility

1491. Some commenters request that transmission providers reflect the full breadth of benefits in cost allocation methods for Long-Term Regional Transmission Facilities while also supporting flexibility.[3178] Vistra asserts that benefits considered in cost allocation should not be confined to a prescriptive list.[3179] NESCOE argues that the Commission should include a list of benefits in the final order as a required starting point and allow transmission providers to add or subtract benefits from the list on compliance following consultation with states in their transmission planning region.[3180]

c. Disagree With Proposal, Mostly Require Benefits

1492. Some commenters disagree with the Commission's proposal, arguing that the Commission should require transmission providers to account for a minimum set of benefits in cost allocation.[3181] Indicated U.S. Senators and Representatives argue that unless all benefits and costs are incorporated into transmission planning and cost allocation, the result will be biased, resulting in unjust and unreasonable costs and cost allocation.[3182] Acadia Center and CLF contend that failure to consider a minimum set of benefits could result in the failure to select transmission projects that would have benefited customers.[3183] Certain TDUs argue that guardrails should be put in place to require transmission providers to adequately define quantifiable benefits and to make transparent their method for identifying benefits; however, Certain TDUs contend that the

[3164] California Municipal Utilities Reply Comments at 5–6 (citing ACEG Initial Comments at 26–48, 50–51, 60–63).

[3165] Louisiana Commission Initial Comments at 35.

[3166] APPA Initial Comments at 46.

[3167] National Grid Initial Comments at 26–27.

[3168] City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35–36; Michigan Commission Initial Comments at 9; OMS Initial Comments at 7–8, 14 (citing Organization of MISO States, Inc., *Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects, https://www.misostates.org/images/PositionStatements/OMS_Position_Statement_of_Principles_Cost_Allocation_for_LRTPs.pdf*).

[3169] NARUC Initial Comments at 25, 38.

[3170] Idaho Power Initial Comments at 11; Pacific Northwest Utilities Initial Comments at 6–9; West Virginia Commission Reply Comments at 4.

[3171] West Virginia Commission Reply Comments at 4.

[3172] Southern Initial Comments at 28–30 (citing *Pac. Gas & Elec. Co.* v. *FERC,* 373 F.3d 1315, 1321 (D.C. Cir. 2004)).

[3173] *Id.* at 29–30 (citing *ICC* v. *FERC I,* 576 F.3d at 476–77; *Ill. Com. Comm'n* v. *FERC,* 721 F.3d 764, 777 (7th Cir. 2013) (*ICC* v. *FERC II*); *ICC* v. *FERC III,* 756 F.3d at 564–565).

[3174] Dominion Initial Comments at 43–44.

[3175] Ohio Consumers Reply Comments at 10.

[3176] Ohio Consumers Reply Comments at 11 (citing DC and MD Offices of People's Counsel Initial Comments at 31, 34, 38–39).

[3177] Pennsylvania Commission Initial Comments at 11.

[3178] APPA Initial Comments at 45–46; Massachusetts Attorney General Initial Comments at 21; NESCOE Initial Comments at 72; Vistra Initial Comments at 15.

[3179] Vistra Initial Comments at 15.

[3180] NESCOE Initial Comments at 43, 72.

[3181] Acadia Center and CLF Initial Comments at 16–19; Certain TDUs Reply Comments at 2–3; Indicated U.S. Senators and Representatives Initial Comments at 2; U.S. Climate Alliance Initial Comments at 2; U.S. Senators Supplemental Comments at 2.

[3182] Indicated U.S. Senators and Representatives Initial Comments at 2.

[3183] Acadia Center and CLF Initial Comments at 16–19.

Commission should require transmission providers to account for, at minimum, production cost savings and avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement, as may be refined by transmission planning regions as necessary.[3184] US Climate Alliance states that each transmission planning region could determine additional categories of benefits most relevant to them.[3185]

1493. Other commenters that disagree with the Commission's proposal similarly argue for a required minimum set of benefits, but argue that the Commission should require transmission providers to account for the full list of 12 benefits in the NOPR.[3186] ACEG and PIOs state that it would be unjust and unreasonable for transmission providers to allocate costs in a manner that ignores certain benefits or fails to provide a full accounting of those benefits, including, PIOs assert, cost allocation agreed to by states.[3187] PIOs further argue that allowing transmission providers to agree to a cost allocation method that does not reflect all quantifiable benefits would re-introduce the risk of free ridership.[3188]

1494. Clean Energy Buyers state that they support the Commission requiring each transmission provider to either adopt the benefits identified by the Commission to be used for cost allocation for Long-Term Regional Transmission Facilities or demonstrate why the exclusion of any such benefit(s) is just and reasonable. However, Clean Energy Buyers also recommend that the Commission consider how the factors required for Long-Term Scenarios will translate into benefits and ensure that there is no double-counting of benefits.[3189]

1495. Southwestern Power Group states that existing regional cost allocation methods do not account for the range of benefits that regional transmission expansion can provide. Consequently, Southwestern Power Group argues, the costs of regional transmission projects are allocated to too few of the beneficiaries, discouraging the development of regional transmission projects.[3190]

[3184] Certain TDUs Reply Comments at 2–3.

[3185] U.S. Climate Alliance Initial Comments at 2.

[3186] ACEG Initial Comments at 60; Clean Energy Associations Initial Comments at 20–21, 34; DC and MD Offices of People's Counsel Initial Comments at 20, 34; PIOs Initial Comments at 64–65.

[3187] ACEG Initial Comments at 60–61 (citing *ICC* v. *FERC I,* 576 F.3d at 477); PIOs Initial Comments at 65; PIOs Reply Comments at 3.

[3188] PIOs Initial Comments at 65.

[3189] Clean Energy Buyers Initial Comments at 30.

[3190] Southwestern Power Group Initial Comments at 14–15.

Environmental Groups argue that the Commission must ensure that any cost allocation method agreed to by states complies with the beneficiary-pays principle by showing that the method considers all quantifiable benefits of transmission.[3191]

1496. SPP states that its regional cost allocation method does not quantify the specific benefits of transmission facilities within each planning assessment but instead analyzes the benefits and costs of facilities approved in multiple assessments in a comprehensive manner. SPP states that potential inequities are not appropriately quantified in a single regional planning assessment cycle because potential imbalances in one cycle may be offset in later cycles or changed because of topology. SPP emphasizes that quantification of whether benefits of transmission facilities are roughly commensurate with allocated costs should be performed through multiple transmission planning cycles that evaluate project portfolios, citing SPP's Highway-Byway cost allocation method as an example.[3192]

d. Alignment of Benefits Between Transmission Planning and Cost Allocation

1497. Various commenters proffer arguments as to whether benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities must align with the benefits used in cost allocation. For example, SERTP Sponsors state that there could be differences between the types of benefits used for evaluation and selection and those used for cost allocation, asserting that benefits used in cost allocation must be measured in a consistent and objective manner to limit disputes.[3193]

1498. Some commenters argue that the benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities should closely align with, but need not be the same as, those used in cost allocation.[3194] For example, Clean Energy Associations state that close alignment does not preclude regional variation and points to MISO's Multi-Value Projects' and SPP's Highway/Byway projects' cost allocation methods.[3195]

[3191] Environmental Groups Supplemental Comments at 2.

[3192] SPP Initial Comments at 31.

[3193] SERTP Sponsors Initial Comments at 30–31.

[3194] Clean Energy Associations Initial Comments at 34; Cypress Creek Reply Comments at 14–15; Ørsted Initial Comments at 9.

[3195] Clean Energy Associations Initial Comments at 34–35.

1499. Some commenters argue that the same set of benefits used in transmission planning should be used in cost allocation.[3196] DC and MD Offices of People's Counsel and the New Jersey Commission link such a requirement with the beneficiary-pays principle.[3197] New Jersey Commission states that enforcing the beneficiary-pays principle based on all of a transmission project's quantified benefits is necessary to avoid free-rider problems that could arise, especially in the State Agreement Process.[3198] Additionally, New Jersey Commission states, the policy of preventing states from involuntarily bearing the costs of others' policies must not require states to always pay the full cost of any transmission solution that supports their public policies or prevent states from committing to paying more than what they perceive to be their fair share to overcome disagreements over who will benefit.[3199] Similarly, BP recommends requiring that those benefitting from transmission facilities that meet policy objectives, but without similar policies themselves, be allocated an appropriate share of costs to avoid free ridership.[3200]

1500. Massachusetts Attorney General states that *ex ante* cost allocation methods should reflect the same benefits considered in Long-Term Regional Transmission Planning and not consider benefits in silos.[3201] Ørsted similarly supports a requirement that transmission providers adopt cost allocation methods that recognize the full breadth of benefits that transmission facilities provide.[3202]

1501. PIOs argue that cost allocation is necessarily implicated in the NOPR's preliminary finding that failure to consider a broader set of benefits and beneficiaries of transmission facilities may result in unjust, unreasonable, and unduly discriminatory or preferential rates, reasoning that cost allocation cannot be based on unlawful

[3196] DC and MD Offices of People's Counsel Initial Comments at 34; Fervo Reply Comments at 2–3; New Jersey Commission Initial Comments at 18–23; SEIA Initial Comments at 24; Vermont Electric and Vermont Transco Initial Comments at 4; WATT Coalition Initial Comments at 8.

[3197] DC and MD Offices of People's Counsel Initial Comments at 34 (citing *ICC* v. *FERC I,* 576 F.3d 470; *ICC* v. *FERC II,* 721 F.3d 764; *ICC* v. *FERC III,* 756 F.3d 556); New Jersey Commission Initial Comments at 18–23 (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d at 1262–63; *Entergy Ark.* v. *FERC,* 40 F.4th 689, 701 (D.C. Cir. 2022)).

[3198] New Jersey Commission Initial Comments at 18.

[3199] *Id.* at 21–23.

[3200] BP Initial Comments at 9–12.

[3201] Massachusetts Attorney General Initial Comments at 21.

[3202] Ørsted Initial Comments at 9.

identification of benefits and beneficiaries.[3203]

e. Additional Benefits or Suggestions for Refinement

1502. DC and MD Offices of People's Counsel recommend that the Commission allow Relevant State Entities to propose additional benefit categories for evaluation and to consent to the allocation of costs that align with these additional benefits. At a minimum, DC and MD Offices of People's Counsel argue, costs should be allocated to the benefitting Relevant State Entities.[3204]

1503. California Energy Commission recommends that transmission providers be required to consider equity and environmental justice in the calculation of benefits, including economic, health, and social benefits to disadvantaged communities.[3205] WE ACT recommends that the Commission include non-energy benefits like pollution reduction, health, jobs, and local economic development in the list of benefits that transmission providers should be required to utilize in identifying and evaluating Long-Term Regional Transmission Facility need, selection, and cost allocation.[3206]

1504. Louisiana Commission states that the Commission should permit transmission providers to consider allocations to all cost causers and beneficiaries, including generators.[3207] Vistra argues that if achieving voluntary corporate and utility clean energy goals is factored into demand driving the need for an upgrade, then the costs of such upgrades should not be assigned to regional load.[3208]

3. Commission Determination

1505. We decline to adopt the NOPR proposal to require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.

1506. Instead, as we discuss above in the Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Order No. 1000 Regional Cost Allocation Principles section, we require transmission providers in each transmission planning region to demonstrate on compliance that the required Long-Term Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (*i.e.,* reliability, economic, or transmission needs driven by Public Policy Requirements). While we do not require that cost allocation methods resulting from State Agreement Processes or Long-Term Regional Transmission Cost Allocation Methods that Relevant States Entities indicate they agreed to, must comply with any of the Order No. 1000 regional cost allocation principles, if filed with the Commission, transmission providers must nonetheless demonstrate that either of these types of cost allocation methods will allocate costs in a manner at least roughly commensurate with estimated benefits.[3209] We do not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission. We adopt this modified approach to the relationship of benefits used in Long-Term Regional Transmission Planning and Long-Term Regional Transmission Cost Allocation Methods because it provides transmission providers with flexibility to propose a Long-Term Regional Transmission Cost Allocation Method(s), allowing for negotiation in the Engagement Period, which we believe will increase the chances that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective regional transmission solution will be developed. At the same time, the requirements in this final order to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities will provide transparency and help to ensure a cost allocation is just and reasonable.

1507. We note that this flexible approach is consistent with the approach that the Commission took in Order No. 1000 and in subsequent orders on transmission providers' Order No. 1000 compliance filings, where the Commission allowed a wide variety of cost allocation methods and did not require that such methods specifically account for all benefits used in evaluation and selection processes.[3210] The cost allocation method for MISO's Multi-Value Projects and the SPP Highway/Byway cost allocation method are examples that reflect the flexibility that transmission providers have had in adopting cost allocation methods suited to their circumstances and that may not have been possible under a less flexible approach.

1508. The one exception to that flexibility, however, is the second component of our compliance requirement, that transmission providers must not allocate costs based on project types; namely, reliability, economic, or Public Policy Requirements needs-driven cost allocation methods. As described in the Long-Term Regional Transmission Facility Cost Allocation Compliance with Existing Six Order No. 1000 Regional Cost Allocation Principles section, we adopt this requirement because permitting such project-type-limited cost allocation methods for Long-Term Regional Transmission Facilities would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final order. As we note above in the Need for Reform section, allocating costs based on these project types would result in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Allocating costs based on these project types could, for example, encourage the selection of transmission facilities based on either their economic or reliability benefits alone rather than based on an evaluation of the wider range of benefits that they may provide. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments. We further find that permitting the use of such project-type-limited cost allocation methods for Long-Term Transmission Facilities would not allocate costs in a manner that is at least roughly commensurate to estimated benefits.

1509. We decline to adopt the NOPR proposal to require transmission providers to evaluate benefits over a 20-year time horizon for Long-Term Regional Transmission Planning for

[3203] PIOs Initial Comments at 71.

[3204] DC and MD Offices of People's Counsel Initial Comments at 34.

[3205] California Energy Commission Initial Comments at 3.

[3206] WE ACT Initial Comments at 5.

[3207] Louisiana Commission Initial Comments at 32.

[3208] Vistra Initial Comments at 21–22.

[3209] *See ICC* v. *FERC I,* 576 F.3d at 477; *ICC* v. *FERC III,* 756 F.3d at 564.

[3210] Order No. 1000, 136 FERC ¶ 61,051 at PP 560, 624.

purposes of cost allocation. Given our decision to not require transmission providers to explain the benefits that they are using in cost allocation for Long-Term Regional Transmission Facilities, we believe this proposal is moot.

1510. We acknowledge New Jersey Commission's concern that permissive state-negotiated cost allocation could result in free riders. However, we note that, even for cost allocation methods filed pursuant to a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed, the costs allocated in accordance with such methods must be, as noted above, at least roughly commensurate with estimated benefits consistent with legal precedent. On compliance with this final order, the Commission will evaluate whether any cost allocation method agreed to pursuant to a State Agreement Process, or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to, and filed with the Commission, allocates the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with the estimated benefits. Further, we believe that New Jersey Commission's concern is reduced by our modification to the NOPR proposal to require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method that must be used where a State Agreement Process fails to result in agreement; to the extent Relevant State Entities do not agree to a cost allocation method through the State Agreement Process, the transmission provider's ex ante Long-Term Regional Transmission Cost Allocation Method will apply.

1511. Given our modification to the NOPR proposal to not require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, we find moot APPA's request that regional flexibility should include allowing transmission providers to demonstrate on compliance that their existing benefits used for cost allocation of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.[3211]

1512. With respect to the comments of City of New Orleans Council, OMS, Louisiana Commission, and Michigan Commission arguing that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2,[3212] which states that ''[c]ost allocation should be as granular and accurate as possible,'' [3213] we note that the flexibility we provide as to the consideration of benefits in cost allocation does not prevent transmission providers in a particular transmission planning region from adopting a more granular approach.

1513. With respect to Southern and Dominion's assertions that the Commission must ensure that costs are allocated in a manner that is at least roughly commensurate with benefits by conducting its evaluation of proposed cost allocation methods in a particular manner,[3214] we reiterate that we will apply existing Commission and judicial precedent, including that cited by Dominion and Southern, in our evaluation of any proposed cost allocation methods for Long-Term Regional Transmission Facilities. With respect to Louisiana Commission's assertion that the cost allocation process should be allowed to consider allocations to all cost causers and beneficiaries, including generators,[3215] we continue to adhere to the flexibility we provided in Order No. 1000–A. In that order, we found that with respect to generators being identified as beneficiaries and ultimately responsible for costs, just as each transmission planning region retains the flexibility to define benefit and beneficiary, the public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to generators as beneficiaries that could be subject to regional or interregional cost allocation. However, we also found that any effort to do so must not be inconsistent with the generator interconnection process under Order No. 2003 because, as we stated in Order No. 1000, the generator interconnection process and interconnection cost recovery were outside the scope of that rulemaking.[3216]

1514. We find Pacific Northwest Utilities' assertion that costs allocated to transmission providers in non-RTO/ISO transmission planning regions, like NorthernGrid, must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities,[3217] to be misplaced, as nothing in this final order requires that only transmission providers in non-RTO/ISO transmission planning regions bear the ultimate responsibility for the costs of Long-Term Regional Transmission Facilities. We recognize that, in the absence of a single regional transmission provider who can recover the costs of Long-Term Regional Transmission Facilities on behalf of its transmission-owning members from all of its transmission customers in its transmission planning region, transmission providers in non-RTO/ISO regions require alternative arrangements to allocate and recover the costs of Long-Term Regional Transmission Facilities from the transmission customers that benefit from them. We expect that in non-RTO/ISO transmission planning regions, as is the case with Order No. 1000 regional transmission planning and cost allocation processes today,[3218] transmission providers will establish arrangements to implement the cost allocation methods for Long-Term Regional Facilities and recover the costs of such facilities from the transmission customers that benefit from them.

1515. Some commenters advocate for accounting for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities.[3219] Although we are not requiring transmission providers to account for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities, we are also not foreclosing the possibility that transmission providers and stakeholders may seek to account for certain public

[3211] APPA Initial Comments at 46. We also discuss related concerns in the Cost Allocation for Long-Term Transmission Facilities section, above.

[3212] City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35–36; Michigan Commission Initial Comments at 9; OMS Initial Comments at 7–8, 14.

[3213] OMS Initial Comments at 7–8.

[3214] Southern Initial Comments at 29–30 (citing *ICC* v. *FERC I,* 576 F.3d at 476–77; *ICC* v. *FERC II,* 721 F.3d at 777; *ICC* v. *FERC III,* 756 F.3d at 564–565); Dominion Initial Comments at 43–44 (citing *ICC* v. *FERC I,* 576 F.3d at 477).

[3215] Louisiana Commission Initial Comments at 32.

[3216] Order No. 1000–A, 139 FERC ¶ 61,132 at P 680. While interconnection customers may voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, this process is distinct from allocating costs to generators under the Long-Term Regional Transmission Cost Allocation Method, as the Louisiana Commission appears to contemplate.

[3217] Pacific Northwest Utilities Initial Comments at 9–10.

[3218] *See e.g., Duke Energy Carolinas, LLC,* 147 FERC ¶ 61,241 at P 453; *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206 at P 314.

[3219] *See e.g.,* California Energy Commission Initial Comments at 3 (recommending that equity and environmental justice benefits be accounted for in cost allocation, including economic, health, and social benefits to disadvantaged communities); WE ACT Initial Comments at 5 (recommending the following benefits be accounted for in cost allocation: pollution reduction, health, jobs, and local economic development).

policy benefits when developing Long-Term Regional Transmission Cost Allocation Methods. We believe that states are well-positioned to value the benefits of achieving their respective public policy goals, consistent with past precedent in which we have affirmed the use of public policy benefits in regional transmission planning cost allocation,[3220] and they or other stakeholders can similarly do so through engagement with transmission providers in their efforts to develop Long-Term Regional Transmission Cost Allocation Methods. In addition, to the extent states believe that a particular Long-Term Regional Transmission Facility would help achieve their public policy goals, we note our adoption in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order of opportunities for Relevant State Entities to voluntarily fund a portion of the cost of a Long-Term Regional Transmission Facility so that the facility can qualify for selection.[3221] The rule, consistent with the cost causation principle, does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities.[3222]

[3220] As noted in the Evaluation of the Benefits of Regional Transmission Facilities section, RTOs/ISOs that have used some form of public policy benefit in regional transmission planning include PJM and NYISO. Although explicitly *not* part of PJM's Order No. 1000 regional transmission planning, PJM uses a State Agreement Approach to allow the development of public policy projects. *See PPL Elec. Utils. Corp.,* 181 FERC ¶ 61,178 at P 33 (finding that ''allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects''). NYISO provides for cost allocations developed by the New York State Public Service Commission for transmission projects developed to meet public policy needs. *See Consol. Edison Co. of N.Y., Inc.,* 180 FERC ¶ 61,106 at P 50 (finding that a volumetric load-ratio share cost allocation for certain local transmission upgrades was appropriate because the projects ''benefit customers throughout the state insofar as they facilitate compliance with the New York State climate and renewable energy goals as required by New York State law and have been determined by the NYPSC to be necessary to meet such obligation'').

[3221] *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[3222] *See Coal. of MISO Transmission Customers* v. *FERC,* 45 F.4th 1004, 1009 (D.C. Cir. 2022) (''The cost-causation principle requires that 'the cost of transmission facilities 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.''') (cleaned up) (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 53); *ICC* v. *FERC I,* 576 F.3d at 477.

D. Miscellaneous Cost Allocation Comments and Proposals

1. Comments

1516. Some commenters discuss the appropriate time frame for cost allocation for Long-Term Regional Transmission Facilities. Dominion states that costs should not be allocated until closer in time to when a transmission project will be built and beneficiaries identified rather than when the Long-Term Regional Transmission Facilities are identified.[3223] Ohio Consumers state that cost allocation decisions must be made on the basis of current or near-term transmission needs, and the Commission should not require subsidization for transmission lines on the theory that the line may be needed to serve future generation.[3224] OMS supports a requirement that transmission providers identify beneficiaries of transmission projects before any costs are allocated.[3225]

1517. Acadia Center and CLF state that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes.[3226]

1518. Some commenters stress the importance of cost containment oversight by the Commission. Joint Commenters support a cost management framework overseen by the Commission ensuring that the costs and benefits on which transmission projects are initially approved for cost allocation remain within initially contemplated parameters.[3227] State Water Contractors assert that the need for cost containment is acute for consumers in California, asserting that the CAISO high voltage transmission access charge has increased nearly 136% over the last decade. State Water Contractors argue that as increases in transmission costs have a direct impact on the cost of water delivery and treatment and given that water and energy are particularly intertwined in California, cost containment and regional flexibility are essential components to the justness and reasonableness of any final order.[3228]

1519. Ohio Consumers state that the Commission should require that the transmission providers implementing any Long-Term Regional Transmission Planning requirements give appropriate consideration to public grants and other external sources of funding in any cost allocation processes, adding that transmission providers should first seek public grants prior to charging customers, because infrastructure funds must be accounted for, or else they would distort cost allocation processes.[3229]

1520. NextEra renews its request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of state right-of-first-refusal rights and require the direct assignment of such costs to customers in the incumbent transmission owner's zone.[3230]

[3223] Dominion Initial Comments at 42.

[3224] Ohio Consumers Initial Comments at 19.

[3225] OMS Initial Comments at 9.

[3226] Acadia Center and CLF Initial Comments at 17.

[3227] Joint Commenters Reply Comments at 1.

[3228] State Water Contractors Reply Comments at 2–3.

2. Commission Determination

1521. We decline to adopt a particular time frame for determining the cost allocation for a Long-Term Regional Transmission Facility, as requested by Dominion, Ohio Consumers, and OMS. We believe that imposing a standardized time frame to determine cost allocation is unnecessary and could impede the regional flexibility that we provide to transmission providers under this final order. However, as discussed above in the Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Regional Cost Allocation Principles section, if only a Long-Term Regional Transmission Cost Allocation Method is available for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), the determination of the applicable cost allocation must occur by or before its selection.

1522. We find Acadia Center and CLF's assertion that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes to be outside the scope of this proceeding, as is NextEra's request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of a state right of first refusal and require the direct assignment of such costs to customers in the incumbent transmission owner's zone. These suggestions are beyond the scope of the Commission's NOPR proposals and we believe that the record

[3229] Ohio Consumers Reply Comments at 15 (citing Infrastructure Investment and Jobs Act of 2021, Public Law 117–58, 135 Stat 429).

[3230] NextEra Reply Comments at 26.

in this proceeding is insufficient to proceed with them.

1523. We also find outside the scope of this proceeding various commenters' statements regarding cost containment. We note that the Commission is examining issues related to transmission planning and cost containment in other proceedings.[3231]

VII. Construction Work in Progress Incentive

A. NOPR Proposal

1524. In the NOPR, the Commission proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of Construction Work In Progress (CWIP) costs in rate base (CWIP Incentive) for Long-Term Regional Transmission Facilities.[3232] The Commission noted that transmission providers may still accrue carrying costs incurred during the pre-construction or construction phase as Allowance for Funds Used During Construction (AFUDC) and only recover those costs from customers after the project is in service, in accordance with generally accepted utility accounting principles for AFUDC.[3233] The Commission explained that this proposal would not affect Commission policy and regulations established before Order No. 679.[3234]

B. Comments

1. Interest in the NOPR Proposal

1525. Many commenters support the Commission's NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive and generally support permitting cost recovery instead through AFUDC, agreeing that extending the CWIP Incentive to Long-Term Regional Transmission Facilities would expose ratepayers to risks and cost burdens by requiring them to pay for Long-Term Regional Transmission Facilities that receive the incentive prior to those facilities being placed into service.[3235]

1526. California Commission and New England Systems argue that there is no evidence that any of the incentives established under FPA section 219, including the CWIP Incentive, have spurred investment in transmission infrastructure.[3236] California Commission argues that there was a great need to develop new transmission to bolster reliability and alleviate congestion when the CWIP Incentive was first introduced in Order No. 679, but that the prior decline in transmission investment has since been reversed.[3237] Further, California Commission argues that an inability to receive the CWIP Incentive would not present a barrier to entry for transmission development,[3238] stating that disallowing the CWIP Incentive for Long-Term Regional Transmission Facilities would affect incumbent and nonincumbent transmission developers equally, and that developers could continue to seek the CWIP Incentive for economic and reliability transmission projects.[3239] Louisiana Commission states that if an independent transmission developer or utility has won a competitive bidding process to construct transmission facilities, that entity should have the financial wherewithal to finance the project without a loan from ratepayers.[3240]

1527. Several commenters assert that the CWIP Incentive shifts risks to customers.[3241] Pennsylvania Commission, Large Public Power, and Resale Iowa argue that allowing the CWIP Incentive could substantially increase the risk of customers paying for transmission facilities that are never built and from which they derive no benefit, leading to rates that are unjust and unreasonable.[3242] NARUC, New England Systems, and Virginia Attorney General agree with the proposed reform because it better aligns risk and reward between shareholders and customers with respect to Long-Term Regional Transmission Facilities.[3243]

1528. Several other commenters state that the longer the transmission planning horizon, the higher the risk that resulting transmission facilities will not be needed, which may result in stranded costs.[3244] For this reason, Industrial Customers state that shifting risks from transmission developers to customers is particularly problematic for Long-Term Regional Transmission Facilities.[3245] Dominion states that it does not take a position on the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, but nevertheless asserts that shifting the risk for long-term transmission projects to transmission providers will help ensure that only those long-term projects that are ''confidently needed'' will be developed. However, for states that may

[3231] *See, e.g.,* Supplemental Notice of Technical Conference, Transmission Planning and Cost Management, Docket No. AD22–8–000 (Oct. 4, 2022).

[3232] NOPR, 179 FERC ¶ 61,028 at PP 328–329 n.522–523, 525–527 (citing Order No. 679, 71 FR 43294 (July 31, 2006), 116 FERC ¶ 61,057 at PP 9, 116–117, n.70). The Commission stated that the Commission has also provided that any public utility engaged in the sale of electric power for resale can file to include in rate base up to 50% of CWIP, subject to limitations. *Construction Work in Progress for Pub. Utils.; Inclusion of Costs in Rate Base,* Order No. 298, 48 FR 24323 (June 1, 1983), FERC Stats. & Regs. ¶ 30,455 (1983) (cross-referenced at 23 FERC ¶ 61,224), *order on reh'g,* 25 FERC ¶ 61,023 (1983). NOPR, 179 FERC ¶ 61,028 at P 329 n.524.

[3233] NOPR, 179 FERC ¶ 61,028 at P 333.

[3234] *Id.* P 333 n.530. There, the Commission stated that public utility transmission providers would still be allowed to request 50% CWIP in rate base, as is permitted pursuant to 18 CFR 35.25(c)(3), subject to an FPA section 205 filing detailing how the request meets the requirements of Order No. 298. The Commission believed that the ability to include 50% CWIP in rate base, if requested and granted, reflects a more reasonable sharing of risks and benefits than the CWIP Incentive for Long-Term Regional Transmission Facilities given the greater uncertainty inherent in Long-Term Regional Transmission Planning, as proposed in this NOPR.

[3235] American Municipal Power Initial Comments at 34; APPA Initial Comments at 6, 46–47; California Commission Initial Comments at 58; California Water Initial Comments at 19–20; Clean Energy Buyers Initial Comments at 30–31; ELCON Initial Comments at 19; Industrial Customers Initial Comments at 24–26; Joint Consumer Advocates Initial Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4; Large Public Power Initial Comments at 41–42; Louisiana Commission Initial Comments at 36; Massachusetts Attorney General Initial Comments at 23; NARUC Initial Comments at 54–55; NASUCA Initial Comments at 8–9; NESCOE Initial Comments at 73; Nevada Commission Initial Comments at 14; North Carolina Commission and Staff Initial Comments at 17–18; NRG Initial Comments at 21–22; Ohio Commission Federal Advocate Initial Comments at 15–16; Ohio Consumers Initial Comments at 29; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; Resale Iowa Initial Comments at 2, 12–13; Six Cities Initial Comments at 11; State Agencies Initial Comments at 24; TAPS Initial Comments at 5, 27–29; Transmission Dependent Utilities Initial Comments at 2–4; Virginia Attorney General Initial Comments at 4–6.

[3236] California Commission Reply Comments at 11–12; New England Systems Reply Comments at 15–16.

[3237] California Commission Reply Comments at 8–10 (citing US DOE, *National Electric Transmission Congestion Study,* at 21(Sept. 2020), *https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf*).

[3238] *Id.* at 19–20 (citing CAISO Initial Comments at 44).

[3239] *Id.*

[3240] Louisiana Commission Initial Comments at 36.

[3241] California Commission Reply Comments at 14; Large Public Power Initial Comments at 41; Louisiana Commission Initial Comments at 36; NARUC Initial Comments at 55–56; New England Systems Reply Comments at 15; Ohio Commission Federal Advocate Initial Comments at 16; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12–13; Virginia Attorney General Reply Comments at 2.

[3242] Large Public Power Initial Comments at 41; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12–13.

[3243] NARUC Initial Comments at 55–56; New England Systems Reply Comments at 15 (citing NARUC Initial Comments at 56); Virginia Attorney General Reply Comments at 2 (citing NARUC Initial Comments at 55).

[3244] Clean Energy Buyers Reply Comments at 10–11; Dominion Initial Comments at 53–54; Industrial Customers Reply Comments at 9; Transmission Dependent Utilities Reply Comments at 4; Virginia Attorney General Reply Comments at 3.

[3245] Industrial Customers Reply Comments at 9.

allow or require the inclusion of the CWIP Incentive in rate base, Dominion states that the Commission should allow for deference to the state cost recovery structure.[3246]

1529. Several commenters suggest that such reform may mitigate certain risks of the transmission provider over-building the system.[3247] For example, Massachusetts Attorney General and North Dakota Commission state that the Commission's proposed limit on the CWIP Incentive would provide ratepayers greater protection from financing inefficient or over-built regional transmission projects.[3248] New England Systems argue that entities in favor of continuing the CWIP Incentive gain financially from the incentive.[3249] Industrial Customers state that the alleged benefits of the CWIP Incentive to customers are tenuous at best.[3250]

1530. Multiple commenters suggest that prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive may improve the planning and building of new transmission facilities.[3251] New England Systems, PJM States, and North Carolina Commission and Staff assert that removing the CWIP Incentive will appropriately reduce incentives to over-build transmission, which could lead to rates being unjust and unreasonable.[3252] Similarly, US Climate Alliance supports prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, as doing so would align incentives for transmission providers to deliver transmission projects on time and within budget.[3253]

1531. California Commission argues that money paid earlier as CWIP is more valuable than money paid later and that comparisons of savings under the CWIP Incentive and under AFUDC are only meaningful if an interest adjustment is made to account for the time in which payments are made.[3254] Industrial Customers explain that, to customers, the difference between the AFUDC and CWIP approaches is primarily the time value of money.[3255] Kentucky Commission Chair Chandler, NASUCA, and California Commission express concern that today's ratepayers are forced to pay for tomorrow's transmission projects, which they refer to as intergenerational inequity, and they are especially concerned if a project will not provide service until a much later date.[3256]

2. Concerns With the NOPR Proposal

1532. Many commenters oppose the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive.[3257] Several commenters cite the Commission's findings in Order No. 679 explaining that the CWIP Incentive can help remove a disincentive to construct new transmission infrastructure, which can involve very long lead times and considerable risk to the utility that the project may not go forward.[3258] National Grid and Avangrid, for example, argue that Long-Term Regional Transmission Facilities will likely have very long lead times and place even greater risk on transmission providers relative to transmission facilities planned and developed on a more typical timeframe.[3259] Similarly, WIRES argues that the rationale underlying the CWIP Incentive remains valid today.[3260]

1533. Some commenters also cite the Commission's 2012 Transmission Incentive Policy Statement as support for the CWIP Incentive as a risk-reducing mechanism to transmission providers, which these commenters state can increase credit ratings and lower capital costs.[3261] In addition, several commenters reference Commission findings in numerous prior incentive proceedings where the Commission has affirmed the benefits that the CWIP Incentive provides to customers and transmission providers, attesting that the NOPR proposal is in direct opposition to such findings.[3262]

1534. Some commenters assert that the NOPR proposal runs counter to obligations established in the Energy Policy Act of 2005 and FPA section 219 to facilitate capital investment in transmission infrastructure and would likely impede the development of regional transmission facilities identified to meet changes in the resource mix and demand.[3263]

1535. Numerous commenters argue that the proposal runs counter to the objectives of the NOPR that seek to encourage the development and completion of regional transmission facilities needed to address changes in

[3246] Dominion Initial Comments at 53.

[3247] Massachusetts Attorney General Initial Comments at 24–25; North Carolina Commission and Staff Initial Comments at 18; North Dakota Commission Initial Comments at 6; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

[3248] Massachusetts Attorney General Initial Comments at 24–25; North Dakota Commission Initial Comments at 6.

[3249] New England Systems Reply Comments at 15–16 (citing Avangrid Initial Comments at 26).

[3250] Industrial Customers Reply Comments at 9–10.

[3251] North Carolina Commission and Staff Initial Comments at 18; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

[3252] New England Systems Reply Comments at 14–15; North Carolina Commission and Staff Initial Comments at 18; PJM States Initial Comments at 13.

[3253] US Climate Alliance Initial Comments at 2.

[3254] California Commission Reply Comments at 13.

[3255] Industrial Customers Reply Comments at 9.

[3256] Kentucky Commission Chair Chandler Initial Comments at 8; NASUCA Initial Comments at 9; California Commission Reply Comments at 17 (citing NASUCA Initial Comments at 9).

[3257] AEP Initial Comments at 38–40; Ameren Initial Comments at 48–51; Avangrid Initial Comments at 24–28; CAISO Initial Comments at 43–45; Consumer Organizations Initial Comments at 7–10; Duke Initial Comments at 44–45; Duquesne Light Initial Comments at 2–6; EEI Initial Comments at 42–45; EEI Reply Comments at 17–18; Entergy Initial Comments at 35–37; Eversource Initial Comments at 31–35; Eversource Reply Comments at 2; Harvard ELI Initial Comments at 7–10; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 65–66; National Grid Initial Comments at 27–30; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13–16; Pattern Energy Initial Comments at 34–36; PG&E Initial Comments at 18–20; PPL Initial Comments at 29–30; SoCal Edison Initial Comments at 13–14; Transource Initial Comments at 3; WIRES Initial Comments at 17–19.

[3258] Ameren Initial Comments at 49; EEI Initial Comments at 42–43; EEI Reply Comments at 17–18; Eversource Reply Comments at 2; MISO TOs Initial Comments at 66; National Grid Initial Comments at 28–29; WIRES Initial Comments at 17–18 (all citing Order No. 679, 116 FERC ¶ 61,057 at P 115).

[3259] Avangrid Reply Comments at 6–7; National Grid Initial Comments at 28–29.

[3260] WIRES Initial Comments at 17–18.

[3261] Ameren Initial Comments at 49; EEI Initial Comments at 42; Eversource Initial Comments at 32 (all citing *Promoting Transmission Investment Through Pricing Reform,* Policy Statement, 141 FERC ¶ 61,129, at P 12 (2012)).

[3262] AEP Initial Comments at 38 (citing *Ne. Utils. Serv. Co. & Nat'l Grid USA,* 125 FERC ¶ 61,183, at P 89 (2008)); Ameren Initial Comments at 49 (citing *United Illuminating,* 119 FERC ¶ 61,182, at P 63 (2007)); Duquesne Light Initial Comments at 3 (citing *Xcel Energy Servs., Inc.,* 121 FERC ¶ 61,284, at P 58 (2007); *Am. Elec. Power Service Corp.,* 116 FERC ¶ 61,059, at P 3 (2006)); EEI Initial Comments at 44 (citing *PPL Elec. Utils. Corp.,* 123 FERC ¶ 61,068, at PP 42–43 (2008), *reh'g denied,* 124 FERC ¶ 61,229 (2008)); National Grid Initial Comments at 29 (citing *Tucson Elec. Power Co.,* 174 FERC ¶ 61,223, at P 25 (2021); *S. Cal. Edison Co.,* 172 FERC ¶ 61,241, at P 31 (2020); *United Illuminating Co.,* 167 FERC ¶ 61,126, at P 36 (2019)); MISO TOs Initial Comments at 66–67 (citing *PJM Interconnection, L.L.C.,* 135 FERC ¶ 61,229, at P 78 (2011); *Duquesne Light Co.,* 166 FERC ¶ 61,074, at P 32 (2019); *United Illuminating, Co.,* 167 FERC ¶ 61,126 at P 36; *GridLiance W. Transco LLC,* 164 FERC ¶ 61,049, at P 25 (2018); *NextEra Energy Transmission N.Y., Inc.,* 162 FERC ¶ 61,196, at P 64 (2018); *PJM Interconnection, L.L.C.,* 158 FERC ¶ 61,089, at P 33 (2017); *Duquesne Light Co.,* 179 FERC ¶ 61,218, at P 17 (2022)); New York TOs Initial Comments at 23 (citing *Okla. Gas & Elec. Co.,* 133 FERC ¶ 61,274, at P 48 (2010); *Pepco Holdings, Inc.,* 125 FERC ¶ 61,130, at P 63 (2008)).

[3263] Ameren Initial Comments at 48; CAISO Initial Comments at 43–44; EEI Initial Comments at 42–43; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 71–72; National Grid Initial Comments at 28; PPL Initial Comments at 29–30; WIRES Initial Comments at 17–18.

the resource mix or demand over a longer time horizon.[3264] For example, CAISO, MISO TOs, and Avangrid suggest that it is counterintuitive for the Commission to acknowledge a lack of regional transmission facilities in the NOPR, yet propose to undo the most reasonable tool that aids cash flow and reduces uncertainty associated with building those facilities.[3265] Certain commenters state that the CWIP Incentive assists with getting needed transmission projects built.[3266] AEP and Avangrid state that the CWIP Incentive is particularly well-suited to incentivizing the type of large, regional transmission projects that the Commission hopes to increase through the NOPR, which often present higher costs, longer lead times, an increase in possible rate shock, and present cash flow difficulties.[3267]

1536. Several commenters point to cash flow benefits enabled through the CWIP Incentive and associated benefits to customers.[3268] For example, New York TOs and PG&E contend that the cash flow benefits from the CWIP Incentive allow a utility to reduce the need for external financing and instead allocate capital to other projects that benefit additional ratepayers.[3269]

1537. Several commenters contend that the Commission has failed to adequately justify the NOPR proposal, asserting that the rationale is weak or arguing that the Commission has not shown that its existing policy is unjust and unreasonable.[3270] MISO TOs argue that the Commission's claim that ratepayers do not receive benefits from the regional transmission facilities during the construction period is unsupported by precedent or analysis and is contrary to longstanding Commission policy. Further, they observe that a transmission facility cannot be developed and placed into service overnight, so artificially dividing up the customer benefits to pre-operation and post-operation ignores the realities of transmission development.[3271] Where the proposal identified that additional ratepayer protections may be necessary to balance customers' interest in just and reasonable rates against investors' interest in earning a return on invested capital or mitigating against over-investment in regional transmission facilities, MISO TOs reiterate that the CWIP Incentive's benefits promote just and reasonable rates by providing incentives encouraging transmission construction consistent with the Commission's FPA mandate and assert that an investor's rate of return is set in unrelated proceedings.[3272]

1538. Pattern Energy states that the Commission has provided no policy justification or factual basis to distinguish the risk incurred during the planning phase from other risk factors, such as size, scope, or cost, which it asserts is a departure from the Order No. 679 policy on the CWIP Incentive.[3273]

1539. Many commenters also argue that, while the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive is intended to mitigate shifting too much risk to customers, the proposal ignores many of the benefits that the current CWIP Incentive policy providers to customers.[3274] EEI argues that commenters that support the proposal also fail to recognize these benefits and the important role that this incentive serves in facilitating new transmission investment.[3275] Many commenters that oppose the NOPR proposal tout such benefits, such as improved cash flow and the ability for transmission providers to secure better financing through higher credit ratings, resulting in lower interest expense costs that benefit customers.[3276] Consumer Organizations and Eversource contend that carrying a significant amount of debt in AFUDC rather than being recovered through the CWIP Incentive can result in lower credit ratings and higher capital costs, which are passed through to customers, and assert that "with AFUDC, consumers are likely to pay more in the long run." [3277]

1540. Some commenters state that the CWIP Incentive helps to avoid rate shock and provides other cost savings relative to AFUDC.[3278] Avangrid states that arguments about the sharing of risk between utilities and customers that the Commission used to support the NOPR proposal fail to consider the budgeting risk to customers under the AFUDC approach, and claims that these arguments ignore the benefit of price stability.[3279]

1541. Several commenters state that the Commission can take more targeted action to address concerns of uncertainty in Long-Term Regional Transmission Planning rather than prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, for instance, by ensuring sufficiently robust selection criteria, project review, and

[3264] AEP Initial Comments at 39; Ameren Initial Comments at 50–51; Avangrid Initial Comments at 25; Avangrid Reply Comments at 6–8; Eversource Initial Comments at 2, 31–32; MISO TOs Initial Comments at 70–76; Pattern Energy Initial Comments at 35–36; PG&E Initial Comments at 18–19.

[3265] Avangrid Reply Comments at 7 (citing CAISO Initial Comments at 45; MISO TOs Initial Comments at 71–72, 74–75); CAISO Initial Comments at 45; MISO TOs Initial Comments at 74–76 (citing NOPR, 179 FERC ¶ 61,028 at PP 1, 9, 25, 35, 47, 330–331).

[3266] AEP Initial Comments at 39; Ameren Initial Comments at 50; Avangrid Initial Comments at 26; MISO TOs Initial Comments at 69.

[3267] AEP Initial Comments at 39; Avangrid Reply Comments at 10.

[3268] AEP Initial Comments at 38–39; Ameren Initial Comments at 49; Avangrid Initial Comments at 25; EEI Initial Comments at 44–45; EEI Reply Comments at 17; Entergy Initial Comments at 37; Eversource Initial Comments at 31; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 66–67, 71, 74–76; National Grid Initial Comments at 28–29; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13; Pattern Energy Initial Comments at 35; PG&E Initial Comments at 19; Transource Initial Comments at 3; WIRES Initial Comments at 17–18.

[3269] New York TOs Initial Comments at 23–24; PG&E Initial Comments at 19.

[3270] Ameren Initial Comments at 50–51; Duke Initial Comments at 44–45; Duquesne Light Initial Comments at 2–3; EEI Initial Comments at 44–45; Eversource Initial Comments at 33–34; MISO TOs Initial Comments at 66–67 (citing NOPR, 179 FERC ¶ 61,028 at P 331); Pattern Energy Initial Comments at 35.

[3271] MISO TOs Initial Comments at 69 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

[3272] *Id.* at 72–73 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

[3273] Pattern Energy Initial Comments at 35.

[3274] AEP Initial Comments at 38–39; Ameren Initial Comments at 48–51; Avangrid Initial Comments at 27–28; Duke Initial Comments at 45; Duquesne Light Initial Comments at 3–5; EEI Initial Comments at 44–45; EEI Reply Comments at 18; Eversource Initial Comments at 31–34; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66–76; National Grid Initial Comments at 29; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13–14; PG&E Initial Comments at 19–20; SoCal Edison Initial Comments at 3, 13–14; WIRES Initial Comments at 18–19.

[3275] EEI Reply Comments at 18 (citing NASUCA Initial Comments at 8–9; Transmission Dependent Utilities Initial Comments at 2–4).

[3276] Ameren Initial Comments at 42, 50; Avangrid Initial Comments at 27; Duke Initial Comments at 45; Duquesne Light Initial Comments at 4–6; EEI Initial Comments at 44–45; MISO TOs Initial Comments at 66–67; PG&E Initial Comments at 19.

[3277] Consumer Organizations Initial Comments at 7–8; Eversource Reply Comments at 4 (quoting Consumer Organizations Initial Comments at 7).

[3278] AEP Initial Comments at 38–39; Ameren Initial Comments at 50; Avangrid Initial Comments at 27–28; Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4–9); Consumer Organizations Initial Comments at 7–10; Duquesne Light Initial Comments at 4; EEI Initial Comments at 44; EEI Reply Comments at 17–18; Eversource Initial Comments at 31–32; Eversource Reply Comments at 4–5; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66–76; National Grid Initial Comments at 28–29; New York TOs Initial Comments at 23–24; PG&E Initial Comments at 19; PG&E Reply Comments at 13–14; SoCal Edison Initial Comments at 13–14; WIRES Initial Comments at 19.

[3279] Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4–9).

approval processes.[3280] CAISO contends that these measures are more appropriate ways to account for the root cause of the risk of over-building and to ensure that customers are protected from the costs of transmission facilities that may be less certain.[3281] R Street states that the NOPR's proposal to remove the CWIP Incentive by itself will not thwart increasing transmission costs, and the Commission must recognize preserving and expanding competition as a way to contain costs.[3282]

1542. Eversource and New York Transco assert that case-by-case evaluation for any request for transmission incentives, including the CWIP Incentive, affords interested parties the opportunity to intervene and provide comments, culminating in a Commission determination of whether the incentive is just and reasonable, thereby protecting customer interests.[3283]

1543. Eversource, Harvard ELI, and National Grid state that it would be best to make changes in incentives policy in a comprehensive transmission incentives rulemaking instead of in this final order.[3284] Eversource and National Grid argue that, at a minimum, the Commission should defer a decision on the CWIP Incentive to the rulemaking proceeding on transmission incentives in Docket No. RM20–10–000, where the Commission has already established a full and complete record.[3285] Harvard ELI suggests that any action on the CWIP Incentive be deferred to another proceeding to develop a holistic package of incentives, penalties, and oversight mechanisms after the Commission has established the full goals and procedural rules for Long-Term Regional Transmission Planning.[3286]

1544. Certain commenters raise concerns of unintended consequences of the proposal. CAISO and Transource state that new transmission developers may be disadvantaged if the Commission prohibits Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive.[3287] Specifically, CAISO notes that the Commission approved a provision in its OATT that permits a nonincumbent transmission developer within CAISO to recover Commission-authorized transmission revenue requirements associated with transmission projects under construction before the facilities are turned over to CAISO operational control, which CAISO contends is a way that it addresses barriers to transmission development by nonincumbent transmission developers.[3288] CAISO contends that the Commission should not preclude transmission developers from using the CWIP Incentive for Long-Term Regional Transmission Facilities, especially because the Commission would continue to allow the CWIP Incentive for reliability and economic transmission projects.[3289]

3. Interaction of the CWIP Incentive With the Abandoned Plant Incentive

1545. Many commenters raise concerns with the interaction between the CWIP Incentive and the transmission incentive that allows applicants to request 100% of prudently-incurred costs associated with abandoned transmission projects be included in transmission rates if such abandonment is outside the control of management (Abandoned Plant Incentive).[3290] APPA, California Commission, Industrial Customers, NARUC, and Virginia Attorney General suggest that unless and until the Commission reconsiders the Abandoned Plant Incentive, customers will continue to face risks associated with Long-Term Regional Transmission Facilities.[3291] Specifically, APPA states that the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive will not necessarily protect customers from the costs of potentially unneeded facilities identified through Long-Term Regional Transmission Planning, given the Commission's policies on recovery of abandoned plant costs (including the Abandoned Plant Incentive under Order No. 679).[3292] Similarly, NARUC, Virginia Attorney General, and Industrial Customers request that the Commission review the current abandoned plant policy to ensure that customer benefits from the adoption of the NOPR proposal with respect to the CWIP Incentive do not disappear if those costs are still recovered from customers as abandoned plant.[3293]

1546. Industrial Customers suggest that, without additional reforms limiting the recovery of abandoned plant costs, customers will continue to face the possibility of paying for transmission that is never built.[3294] Further, Industrial Customers and California Commission state that AFUDC could be a superior approach for customers, but only in a final order that adopts certain protections to ensure that customers do not pay for abandoned plant costs.[3295] Industrial Customers argue that the Commission should adopt customer safeguards for transmission projects that are abandoned, including a more thorough review of whether costs were prudently incurred prior to abandonment.[3296]

C. Commission Determination

1547. We decline to act at this time to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities. We agree with commenters [3297] that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives after the Commission has finalized its Long-Term Regional Transmission Planning reforms. In particular, we conclude that whether the Commission's transmission incentives are appropriately ''benefitting consumers by ensuring reliability and reducing the cost of delivered power'' [3298] is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.

[3280] Avangrid Reply Comments at 8 (citing CAISO Initial Comments at 45); CAISO Initial Comments at 45; EEI Reply Comments at 18; PG&E Reply Comments at 13–14.

[3281] CAISO Initial Comments at 6–7, 45.

[3282] R Street Reply Comments at 2.

[3283] Eversource Reply Comments at 4–5; New York Transco Reply Comments at 7–8.

[3284] Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4–5, 7–8, 10; National Grid Initial Comments at 27.

[3285] Eversource Initial Comments at 33; National Grid Initial Comments at 27.

[3286] Harvard ELI Initial Comments at 4–5, 7–8, 10.

[3287] CAISO Initial Comments at 43–45; Transource Initial Comments at 3.

[3288] CAISO Initial Comments at 43–44 (citing *Cal. Indep. Sys. Operator Corp.,* 146 FERC ¶ 61,237 (2014)).

[3289] *Id.* at 44–45.

[3290] Order No. 679, 116 FERC ¶ 61,057 at P 163.

[3291] APPA Initial Comments at 46–47; California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 24–27; Industrial Customers Reply Comments at 9; NARUC Initial Comments at 55; Virginia Attorney General Initial Comments at 6–7; Virginia Attorney General Reply Comments at 5–6.

[3292] APPA Initial Comments at 46–47.

[3293] Industrial Customers Reply Comments at 10 (citing MISO States Initial Comments at 14; NARUC Initial Comments at 55); NARUC Initial Comments at 55; Virginia Attorney General Reply Comments at 5 (citing NARUC Initial Comments at 55).

[3294] Industrial Customers Initial Comments at 25–26.

[3295] California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 26–27.

[3296] Industrial Customers Reply Comments at 9.

[3297] Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4–5, 7–8, 10; National Grid Initial Comments at 27.

[3298] 16 U.S.C. 824s(a).

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

A. NOPR Proposal

1548. In the NOPR, the Commission proposed to use the discretion afforded by FPA section 309 to amend Order No. 1000's findings and nonincumbent transmission developer reforms in part, so as to permit the exercise of Federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.[3299] The Commission reasoned that given the investment trends observed since Order No. 1000's implementation, it is possible that the Commission's Order No. 1000 nonincumbent transmission developer reforms may be inadvertently discouraging investment in and development of regional transmission facilities to some extent.[3300] Specifically, the Commission posited that 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.[3301]

1549. The Commission preliminarily found that, while the *unconditional* exercise of Federal rights of first refusal for entirely new selected transmission facilities remains unjust and unreasonable, Order No. 1000's remedy—requiring the elimination of *all* Federal rights of first refusal for entirely new selected transmission facilities—was overly broad.[3302] The Commission further preliminarily found that, while Order No. 1000's reforms have a sound theoretical basis, the remedy prescribed by Order No. 1000 failed to recognize that some of the expected benefits from the competitive transmission development processes could be achieved or at least reasonably approximated through other means.[3303]

1550. Accordingly, the Commission proposed to allow transmission providers to propose, pursuant to FPA section 205, new Federal rights of first refusal for incumbent transmission providers, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain requirements described in the NOPR.[3304] The Commission asserted that if the NOPR proposal was adopted, Order No. 1000's findings and mandates would be amended such that joint ownership conditions would presumptively be found to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by transmission providers, if imposed upon the exercise of an incumbent transmission provider's Federal right of first refusal for selected transmission facilities.

1551. The Commission explained that an incumbent transmission provider could establish qualifying joint ownership with unaffiliated nonincumbent transmission developers as defined in Order No. 1000, or another unaffiliated entity, including another incumbent transmission provider.[3305] However, the Commission also proposed that to qualify for the presumption, incumbent transmission providers with a conditional Federal right of first refusal would not be allowed to structure joint-ownership arrangements such that unaffiliated entities were offered less than a meaningful level of participation and investment in the proposed regional transmission facility.[3306] The Commission further explained that an incumbent transmission provider's conditional Federal right of first refusal should not significantly delay the regional transmission planning process or result in prolonged uncertainty regarding which transmission facilities will (or, alternatively, will not) be subject to competitive transmission development processes.[3307]

1552. The Commission noted that proposals for jointly owned regional transmission facilities would still need to be evaluated by transmission providers in the transmission planning region and would not be exempt from selection requirements. However, the Commission also explained that the evaluation process for such jointly owned regional transmission facility proposals would not involve running the region's competitive transmission development process.[3308]

B. Comments

1. General Perspectives and Approach To Reform

1553. Commenters share a variety of perspectives on the track record of competitive transmission development processes, the wisdom of the nonincumbent transmission developer reforms adopted in Order No. 1000, and the steps they believe the Commission should take in response to the concerns identified in the NOPR. Several state entities, customer-affiliated groups, and nonincumbent transmission developers, such as LS Power, NextEra, and the US DOJ and FTC, defend competitive transmission development processes as beneficial and argue for their expansion.[3309] Some US Senators agree, arguing that allowing for a conditional Federal right of first refusal would be anti-competitive, could hinder development of new transmission, and could cause excessive costs to consumers.[3310] On the other hand, representatives of incumbent transmission providers and others (*e.g.,* EEI, WIRES, DATA, the MISO TOs) critique such processes and many call for the Commission to restore unconditional Federal rights of first refusal.[3311] Each side of the debate

[3299] *See* NOPR, 179 FERC ¶ 61,028 at P 351.

[3300] *Id.* P 350.

[3301] *Id.*

[3302] *Id.* PP 351–352, 354.

[3303] *Id.* P 353.

[3304] *Id.* P 354.

[3305] *Id.* P 365.

[3306] *Id.* P 371.

[3307] *Id.* P 366.

[3308] *Id.* P 370.

[3309] *See, e.g.,* American Municipal Power Reply Comments at 3–4; Anbaric Initial Comments at 4–5; California Commission Initial Comments at 100, 103–104; Competition Advocates Supplemental Comments at 1–3 & n.17 (citing Jennifer Chen & Devin Hartman, R Street Institute, *Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles* (May 2022), *http://www.rstreet.org/research/transmission-reform-strategy-from-a-customer-perspective-optimizing-net-benefits-and-procedural-vehicles*); Competition Coalition Initial Comments at 16–22, 68–70; LS Power Initial Comments at 38–39, 44; LS Power Partial Reply Comments at 20–23; LS Power and NRG Supplemental Comments at 38–39; NextEra Initial Comments at 18–19, 24–27, 29; Ohio Consumers Reply Comments at 16–18; Resale Iowa Reply Comments at 5–6; US DOJ and FTC Initial Comments at 7–8, 10–11, 13, 22.

[3310] U.S. Senators Heinrich and Lee Supplemental Comments at 1–2. *See also* Freeport-McMoRan Supplemental Comments at 6 (asserting that the Federal right of first refusal is anticompetitive and would enrich transmission owning utility shareholders).

[3311] *See, e.g.,* DATA Initial Comments at 3–7 (detailing experiences by transmission planning regions and concluding that ''competitive processes have become a distraction from, and an impediment to, the larger goal of expanding the transmission system to support current and future needs''); EEI Initial Comments at 24, 26, 27–31; EEI Supplemental Comments at 1–3 (citing Concentric Energy Advisors, *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits,* at 1 (Aug. 2022) (2022 Concentric Report); DATA Supplemental

Continued

offers consultant reports to substantiate their position, with pro-competition advocates relying on studies by the Brattle Group (Brattle) that present competitive transmission development processes in a largely favorable light,[3312] and advocates for Federal rights of first refusal relying on contrasting studies by Concentric Energy Advisors (Concentric).[3313] In general, pro-competition advocates, such as LS Power, contend that competitive transmission development processes are essential to just and reasonable rates, while representatives of incumbent transmission providers counter that just and reasonable transmission rates are separately and independently ensured by and through FPA section 205 rate proceedings.[3314]

1554. At a high level, pro-competition commenters express concern that the NOPR proposal could divert regional transmission facility development opportunities to incumbent transmission providers, opportunities that would otherwise be subject to competitive transmission development processes. For example, US DOJ and FTC argue that relying on Federal rights of first refusal to address the problems the Commission has identified would eliminate or distort the benefits of competitive transmission development processes, which generally ''make transmission development less costly, more resilient, and more innovative.'' [3315] NESCOE ''implores the Commission to maintain flexibility that enables ISO–NE to issue competitive solicitations to identify projects in furtherance of state laws.'' [3316] Some pro-competition commenters believe that states and state commissions are best positioned to determine whether competition between nonincumbent transmission developers and incumbent transmission providers is beneficial.[3317]

1555. Meanwhile, commenters that generally support Federal rights of first refusal express skepticism that the NOPR proposal would be sufficient to address the identified problems, or offer only qualified support for the NOPR proposal as an inferior alternative to the Commission fully restoring unconditional Federal rights of first refusal.[3318] In addition, if adopted, several incumbent transmission providers advocate for requiring transmission providers to implement the NOPR proposal instead of permitting them to decide whether to implement it.[3319]

1556. While commenters offer numerous variations on these high-level opposing views, several commenters argue that there are problems with the basic structure of competitive transmission development processes and express concerns that generally align with those expressed by the Commission in the NOPR. For example, while not agreeing with the NOPR proposal, ELCON expresses concern that ''current competition regimes have led eligible developers to retreat to their various corners, which reduces transparency, information sharing, and open dialogue in the planning process[,]'' and contends that both incumbent transmission owners and nonincumbent transmission developers have adopted a zero-sum posture to transmission planning that leads to a patchwork of planning and lack of innovation.[3320] Similarly, WIRES, citing a report by Grid Strategies, suggests that reforms under Order No. 1000 often prevent information sharing about transmission needs and available solutions, and lead to less cooperation and coordination within transmission planning regions.[3321] Harvard ELI disagrees, however, arguing that the report cited by WIRES provides evidence that information asymmetry, secrecy, and utilities' incentives demonstrate undue discrimination.[3322]

1557. Though it does not support the NOPR proposal, Cypress Creek contends that Order No. 1000 led to misaligned incentives such that ''competition today has not necessarily fostered just and

Comments at 4); MISO TOs Initial Comments at 53–56; National Grid Initial Comments at 4–5, 31 (doubting that Order No. 1000 competitive transmission development processes have broadly produced beneficial outcomes); PJM Initial Comments at 47–48 (enumerating the challenges faced in and resources required to complete competitive transmission development processes); Vermont Electric and Vermont Transco Initial Comments at 4–5 (referencing ''a number of unintended consequences that have not benefited the regional grid''); WIRES Initial Comments at 14–15; WIRES Reply Comments at 4–8; Xcel Initial Comments at 5 (''[Right of first refusal] elimination was a policy experiment that did not bring about the desired result.'').

[3312] In general, Brattle's analysis has found that competitive transmission development processes have yielded ''cost savings averaging between 20% and 30%'' once historical levels of cost escalation in transmission development were taken into account. *See* Brattle Apr. 2019 Competition Report at 39–43. US DOJ and FTC also contend that there are many instances in which competitive transmission development processes have benefitted consumers. *See* US DOJ & FTC Initial Comments at 13–16 (collecting examples); *but see* DATA Initial Comments at 7–9 (critiquing Brattle's analyses); WIRES Reply Comments at 5 (same).

[3313] In addition to citations to past Concentric reports, DATA attaches to its initial comments a 2022 Concentric report, which DATA characterizes as showing that competitive transmission development processes add significant time, delay customer benefits, and do not produce clear evidence of customer savings given cost cap exclusions and delays. DATA Initial Comments at 1–2, 7–11, 14–15; *id.* at attach. A (2022 Concentric Report). DATA also attaches to its comments a whitepaper that DATA alleges updates the Brattle Apr. 2019 Competition Report, and which DATA contends shows that Order No. 1000-mandated competition resulted in exceeding cost baselines by at least six percent. DATA Supplemental Comments at 3–4; *id.* at attach.: Whitepaper (DATA, *Revisiting the Evidence on Cost Savings from Transmission Competition* (Dec. 2023) (2023 DATA Whitepaper)). *But see* Massachusetts Attorney General Reply Comments at 8–9 (critiquing the 2022 Concentric Report); NextEra Reply Comments at 3, 7–17 (same); *see also* Competition Coalition Supplemental Comments at 2–7 (arguing that, in addition to DATA lacking good cause and failing to file a motion to lodge new evidence, the 2023 DATA Whitepaper fails to, among other things, demonstrate that cost-of-service regulation is as effective as competition in establishing just and reasonable transmission rates).

[3314] *Compare* LS Power Initial Comments at 32–37, *with* Ameren Initial Comments at 36–37, and DATA Initial Comments at 13–14, and MISO TOs Initial Comments at 60–61. Several commenters argue at length about the NOPR proposal's invocation of FPA sections 309 and 206 as legal authority and explore various alternatives. *See, e.g.,* Ameren Initial Comments at 38–39; California Commission Initial Comments at 101–103; DATA Initial Comments at 17–18 & n.43; Eversource Initial Comments at 39–42; Indicated PJM TOs Initial Comments at 34–35; ITC Initial Comments at 36; LS Power Initial Comments at 14, 19–20, 24, 57–61; MISO TOs Initial Comments at 50–53; NextEra Initial Comments at 51–53.

[3315] *See* US DOJ & FTC Initial Comments at 22.

[3316] NESCOE Supplemental Comments at 6–7.

[3317] *E.g.,* California Commission Initial Comments at 104–105; Harvard ELI Initial Comments at 5–6, 31–33; *see also* Minnesota State Entities Initial Comments at 9; Mississippi Commission Reply Comments at 8 & n.31; New Jersey Commission Initial Comments at 37; PIOs Initial Comments at 85; PJM States Initial Comments at 13–14. *But see* NextEra Reply Comments at 23–25 (questioning whether allowing states to dictate the terms of a filed rate would be legally sound); PJM Reply Comments at 25–29 (raising potential legal ambiguities and practical issues).

[3318] *E.g.,* Avangrid Initial Comments at 18–24; DATA Initial Comments at 20–22; Eversource Initial Comments at 35–36, 42–45; Indicated PJM TOs Reply Comments at 2, 13–14; ITC Initial Comments at 32–43; Xcel Initial Comments at 5.

[3319] *See, e.g.,* DATA Initial Comments at 19–21; Exelon Initial Comments at 49–51; National Grid Initial Comments at 36–37; PG&E Initial Comments at 2, 11; PPL Initial Comments at 34; SoCal Edison Initial Comments at 2; WIRES Initial Comments at 16; *see also* LS Power Initial Comments at 74–76 (discussing FPA section 205 rights in various regions); PJM Initial Comments at 30 (questioning whether there are any ''regional differences'' on this policy issue). *But see* Idaho Power Initial Comments at 12 (urging the Commission to ensure that any proposed reforms provide sufficient flexibility to tailor transmission planning and cost allocation processes to accommodate unique regional characteristics).

[3320] ELCON Initial Comments at 21–22; *see also* DATA Reply Comments at 14 (arguing that ''the Order No. 1000 status quo creates an inexorable drive towards minimalist, short-term solutions''). Despite its opposition to the NOPR proposal, ELCON sees some potential benefit of encouraging joint ownership and cooperation-based approaches, which ELCON thinks may help remedy the '''us versus them' problems with the current regional planning process.'' ELCON Initial Comments at 23–24.

[3321] WIRES Supplemental Comments at 4 (citing Rob Gramlich, Richard Doying, & Zach Zimmerman, Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)).

[3322] Harvard ELI Supplemental Comments at 5.

reasonable rates.'' [3323] Similarly, American Municipal Power states that many municipal electric systems are located on the fringe of an incumbent transmission provider's system and would significantly benefit from regional transmission projects that improve reliability, although because such projects require coordination between two incumbent transmission providers, they are ''largely ignored.'' [3324] American Municipal Power also states that another disincentive to incumbent transmission provider regional transmission facility development is the possibility of losing the project to another developer through the competitive process.[3325] While not taking a position on competitive transmission development processes, Indiana Commission agrees that Order No. 1000 has produced unintended consequences, including that transmission development now mostly takes the form of transmission facilities not subject to competitive transmission development processes,[3326] and states that little region-wide economic transmission development is occurring.[3327]

1558. But some commenters, such as NextEra, contend that if regional transmission investment has lagged behind expectations under Order No. 1000, that is a planning issue, not an incentives issue, and that some of the NOPR's proposed transmission planning reforms will help lead to greater investment in regional transmission facilities.[3328] LS Power argues that the NOPR only generally observed that there have been increases in local transmission facility investment and static or declining investment in regional transmission facilities, and did not specify particular transmission planning regions in which this problem is occurring or which incumbent transmission providers face perverse investment incentives.[3329] However, other commenters, such as WIRES, contend that the elimination of Federal rights of first refusal may be connected to flat or declining regional transmission investment,[3330] as suggested by the NOPR.

1559. Finally, several commenters argue that the Commission should not adopt Federal right of first refusal reforms in this docket, but rather explore those and related issues in another forum. Advanced Energy United, Advanced Energy Buyers, State Agencies, and California Commission, for example, urge the Commission to consider these issues either in a different proceeding or at a technical conference.[3331] Competition Advocates support alternative reforms that they argue can better address the problem of perverse incentives, including better enforcement of existing orders or taking action to reduce Order No. 1000 exemptions, and establishing an independent transmission monitor.[3332]

2. Comments on the NOPR's Joint Ownership Proposal

1560. Some commenters, including TAPS, highlight various ways in which the Commission's joint ownership proposal would alleviate challenges associated with current regional transmission planning processes.[3333] Some commenters, such as ELCON and the Omaha Public Power District, argue that the Commission's joint ownership proposal would benefit customers or encourage incumbent transmission providers to pursue larger and more comprehensive transmission solutions to the benefit of customers, and create incentives for transmission providers to find beneficial opportunities and investments for joint ownership partners and customers.[3334] Other commenters agree that adopting the NOPR proposal may incentivize incumbent transmission providers to ''look beyond the provincial'' needs and consider regional and interregional solutions to transmission needs.[3335]

1561. However, numerous commenters criticize the NOPR proposal and its approach to joint ownership partner selection, especially its inclusion of another incumbent transmission provider as a potential joint ownership partner.[3336] In general, these commenters contend that incumbent transmission providers would be free to only team up with fellow incumbent transmission providers with the same interests and exclude others, leading to results that would be contrary to the goals of Order No. 1000. As Anbaric states, two incumbent transmission providers (or their affiliates) could ''team up and swap a portion of their respective projects as a means to satisfy the joint ownership requirement'' and thereby ''maintain the status quo'' [3337] rather

[3323] Cypress Creek Reply Comments at 16.

[3324] American Municipal Power Initial Comments at 31–32.

[3325] *Id.* at 32. However, American Municipal Power states that because regional transmission facilities typically traverse more than one incumbent transmission provider's service territory, allowing individual incumbent transmission providers to exercise a Federal right of first refusal without other reforms also designed to promote coordination and cooperation between such providers would not ''result in a shift from local to regional projects.'' *Id.* (referencing the ''interzonal nature of regional projects'').

[3326] Indiana Commission Initial Comments at 12 (referring to '' 'immediate need reliability' or 'end of life replacement' or 'supplemental' or 'other' '' types of transmission facility projects).

[3327] *Id.*

[3328] *See* NextEra Initial Comments at 18–19, 25; *see also id.* at 43 (arguing that the NOPR proposal is insufficiently based on speculation about potentially flawed investment incentives); Americans for Fair Energy Prices Reply Comments at 5–6; Northwest and Intermountain Initial Comments at 19–20 (arguing that even a limited or conditional right of first refusal eliminates any incentive for the incumbent transmission provider to reduce costs or delays); Ohio Commission Federal Advocate Initial Comments at 18 (arguing that adopting the NOPR proposal would further misalign incentives for incumbent transmission providers, not improve them).

[3329] LS Power Initial Comments at 73–74. *But see* PJM Initial Comments at 30 (questioning whether there are any ''regional differences'' on this policy issue).

[3330] WIRES Reply Comments at 2 (citing WIRES Initial Comments at 13–14).

[3331] Advanced Energy Buyers Initial Comments at 4 n.6; AEE Initial Comments at 4, 35–37; AEE Reply Comments at 31–33; California Commission Initial Comments at 103–104; State Agencies Initial Comments at 11; State Agencies Reply Comments at 6; *see also* Chemistry Council Initial Comments at 8; Enel Initial Comments at 3; Harvard ELI Initial Comments at 7–10; NESCOE Initial Comments at 11, 74–77.

[3332] Competition Advocates Supplemental Comments at 3–4.

[3333] *See* TAPS Initial Comments at 29–30 (stating that joint ownership arrangements provide benefits such as ''improving transmission planning to produce a more efficient build-out; facilitating state siting; making it easier for [load-serving entities] to accept cost increases associated with new transmission by providing a hedge; and reducing the costs of needed facilities''), *id.* at 34–37; *see also* Eversource Initial Comments at 36–39; Pattern Energy Initial Comments at 37; PPL Initial Comments at 32–33; Vermont Electric and Vermont Transco Initial Comments at 4.

[3334] *See* ELCON Initial Comments at 23–24; *see also* Cross Sector Representatives Supplemental Comments at 1 (arguing that the provisions are appropriately tied to collaborative and holistic planning outcomes that provide clear benefits to customers and would benefit the goals enunciated by the Commission throughout this rulemaking process); Omaha Public Power Initial Comments at 5 (suggesting that the joint ownership proposal will likely encourage neighboring incumbent transmission providers to develop facilities that benefit multiple transmission providers under certain conditions); Pattern Energy Initial Comments at 37 (asserting that joint ownership arrangements will open the market to additional investment opportunities for all parties).

[3335] Tabors Caramanis Rudkevich Initial Comments at 2; *see also* Citizens Energy Initial Comments at 9–10; PG&E Initial Comments at 11 (arguing that a conditional Federal right of first refusal will help mitigate development challenges by promoting collaboration between partners).

[3336] *E.g.,* Anbaric Initial Comments at 18; *see also, e.g.,* APPA Initial Comments at 11–12; California Commission Initial Comments at 80–88; Competition Coalition Initial Comments at 49–50; LS Power Initial Comments at 92–94; Massachusetts Attorney General Initial Comments at 48–49; New Jersey Commission Initial Comments at 31–33; NextEra Initial Comments at 49–51; NRECA Initial Comments at 58, 61; PJM States Initial Comments at 14; Policy Integrity Initial Comments at 21–22; TANC Initial Comments at 13; TAPS Initial Comments at 48–51; TAPS Reply Comments at 5–6 & n.25.

[3337] Anbaric Initial Comments at 18.

than advance innovation, cost savings, or new entry. NextEra and others decry this potential outcome, which could keep nonincumbent transmission developers from obtaining investment opportunities.[3338] Relatedly, several commenters argue that the NOPR proposal would raise antitrust and competition concerns,[3339] including US DOJ and FTC, which argue that because the joint venture will not be facing pressure to compete, the conditional Federal right of first refusal does not create the incentive for incumbent transmission providers to seek out the best partner.[3340] In other words, US DOJ and FTC argue, the mere existence of a joint venture partner does not bring competition to a project, nor does it necessarily result in the best partner for a project being selected, in terms of skill, cost, or innovation.[3341]

1562. Commenters also highlight the potential for uncertainty, litigation, and delays in attempting to implement the NOPR proposal. Anbaric asserts that a conditional Federal right of first refusal could add delays due to litigation over whether incumbent transmission providers provided meaningful opportunities to third parties.[3342] EEI cautions against putting transmission providers in a position where they must adjudicate what constitutes meaningful ownership of jointly owned transmission facilities on a case-by-case basis, recommending instead that the Commission provide guidance on the types of ownership rights or operational obligations that will qualify and establish a process for seeking Commission approval in a timely manner for other arrangements.[3343] MISO asserts that the process envisioned by the NOPR would be time-consuming, as would developing a joint ownership proposal, and asks that the Commission adopt clearly defined criteria for joint ownership, such as a *pro forma* agreement, in order not to impede transmission development.[3344] National Grid calls for planning authorities to be given the authority to determine the appropriate criteria and conditions that constitute a valid joint ownership arrangement, though it also asks for guidance regarding particular types of combinations of potential joint owners.[3345]

C. Commission Determination

1563. We decline to act at this time to finalize the NOPR proposal. Rather, we will continue to consider the NOPR proposal and potential Federal right of first refusal issues in other proceedings. We do not adopt in this final order any changes to Order No. 1000's nonincumbent transmission developer reforms.

1564. As summarized above, commenters raise substantial concerns about whether incumbent transmission providers, as a result of Order No. 1000's reforms, face 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. To the extent that incumbent transmission providers face perverse investment incentives, commenters also raise substantial concerns about whether the NOPR proposal adequately and appropriately addresses those incentives and whether adopting the proposal is necessary or appropriate in carrying out the provisions of the FPA. Therefore, after careful consideration of the record, we decline to finalize the NOPR proposal at this time. The Commission will continue to consider potential Federal right of first refusal reforms along with other transmission reforms in the future.[3346]

IX. Local Transmission Planning Inputs in the Regional Transmission Planning Process

A. Need for Reform

1. NOPR

1565. In the NOPR, the Commission explained that it was concerned that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders, and that regional transmission planning processes may not adequately coordinate with local transmission planning processes.[3347] The Commission stated in the NOPR that it was concerned that the lack of minimal standards or specified procedures may contribute to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.[3348] Accordingly, the Commission stated that it believed reforms to better ensure transparency and opportunities for stakeholder engagement may be timely and important in light of the significant investments in transmission that now occur through local transmission planning processes.[3349]

1566. In addition, the Commission explained in the NOPR that it was concerned that, given the age of the Nation's transmission infrastructure, many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating whether those replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address regional transmission needs, and, more generally, that transmission providers developing regional transmission plans may lack the information necessary to identify the benefits that regional transmission facilities may provide in deferring or eliminating the need for in-kind replacements. Specifically, the NOPR stated that in-kind replacements

[3338] *See* Harvard ELI Initial Comments at 35; NextEra Initial Comments at 49–51. In contrast, some commenters such as APPA urge the Commission to adopt a requirement that incumbent transmission providers offer joint ownership on reasonable terms at a load ratio share level to all unaffiliated load-serving entities in the incumbent transmission provider's footprint. *See* APPA Reply Comments at 5–6; TAPS Initial Comments at 30–32 (advocating for a similar proposal).

[3339] *See, e.g.,* Competition Coalition Initial Comments at 59–62; LS Power Initial Comments at 122–125, 131–134; US DOJ & FTC Initial Comments at 17–18.

[3340] US DOJ & FTC Initial Comments at 17.

[3341] *Id.* at 17–18; *see also* LS Power Initial Comments at 93 (arguing that the NOPR proposal would not require any independent check that the incumbent transmission provider is partnering with the entity that offers the most benefits).

[3342] Anbaric Initial Comments at 16; *see also* Avangrid Initial Comments at 18 (noting that establishing a conditional Federal right of first refusal adds a layer of complexity to the development of transmission); NYISO Initial Comments at 55–56 (asking the Commission to consider the complications, disputes, and delays that may arise from attempting to implement a conditional Federal right of first refusal and other practical issues).

[3343] EEI Initial Comments at 36–37; *see also* Ameren Initial Comments at 44; DATA Initial Comments at 21–22; PJM Initial Comments at 4–5, 51–52, 53–54.

[3344] MISO Initial Comments at 80–83; *see also* APPA Initial Comments at 4–7, 20–22 (outlining a detailed proposed implementation process by which APPA believes incumbent transmission providers and load-serving entities could work together and help avoid disputes and delay); Invenergy Reply Comments at 7–8 (calling for the adoption of *pro forma* agreements to ease implementation); TAPS Initial Comments at 53–54 (expressing concern that the NOPR proposal's anticipated period for formulation of joint ownership agreements is too short).

[3345] *See* National Grid Initial Comments at 37.

[3346] We note, for example, the ongoing proceeding in Docket No. AD22–8 on Transmission Planning and Cost Management.

[3347] NOPR, 179 FERC ¶ 61,028 at P 398 & n. 639 (providing that regional transmission planning processes should identify "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual utility transmission providers in their local transmission planning process" (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 148)).

[3348] *Id.*

[3349] *See supra* The Overall Need for Reform section.

of existing transmission facilities are managed by individual incumbent transmission providers according to their company practices, and that there is no requirement that transmission providers plan these in-kind replacement transmission facilities through an Order No. 890-compliant transmission planning process.[3350] The Commission stated that, because in-kind replacement of existing transmission facilities is not subject to any transmission planning process, it was concerned that, absent reform, there may be a lack of coordination between regional transmission planning processes and in-kind replacement of existing transmission facilities to identify whether these replacement transmission facilities could be modified to more efficiently or cost-effectively address transmission needs identified through Long-Term Regional Transmission Planning. The Commission explained that this lack of coordination may result in a regional transmission planning process that fails to identify opportunities to right size planned in-kind replacement transmission facilities and may result in the development of duplicative or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.[3351]

2. Comments

1567. Some commenters argue that the NOPR proposal regarding improved transparency in local transmission planning processes is not justified.[3352] EEI argues that the Commission has not found that any of the approved transmission planning processes under Order Nos. 890 and 1000 are unjust and unreasonable or unduly discriminatory or preferential and that, absent such a finding, the Commission should not move forward with changes to local transmission planning processes.[3353] Idaho Power states that the Commission should not use a general rulemaking to address localized problems.[3354] On the other hand, Indicated PJM TOs state that the NOPR proposal to enhance transparency in the local transmission planning processes is needed in each transmission planning region to satisfy the requirements set forth by Order No. 890.[3355]

1568. With respect to the Commission's proposed right-sizing reforms, LS Power and NextEra argue that the NOPR fails to make findings required under FPA section 206 to permit a right of first refusal for right-sized projects. LS Power and NextEra assert that the NOPR does not satisfy the first prong of FPA section 206, as it fails to make an affirmative finding that either the regional transmission planning process or the local transmission planning process are unjust and unreasonable such that abandonment of the existing tariff provisions is warranted.[3356] Competition Coalition also asserts that the Commission failed to demonstrate the alleged need for reform on any section 206 finding.[3357]

3. Commission Determination

1569. Based on the record, we find that there is substantial evidence to support the conclusion that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform of the local transmission planning process and coordination between the local and regional transmission planning processes, including the evaluation of whether replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address transmission needs.[3358]

1570. Local and regional transmission planning processes serve essential and complementary roles in ensuring that customers' transmission needs are identified and met at a just and reasonable cost, including through the identification, evaluation, and selection of more efficient or cost-effective transmission solutions through regional transmission planning. Information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning, and it is therefore critical that the processes are appropriately designed and aligned to ensure that transmission providers and stakeholders have the information needed, including from the local transmission planning process, to conduct effective regional transmission planning. While the broader reforms directed in this final order are focused on improving the regional transmission planning process, we nonetheless have identified discrete deficiencies in the local transmission planning process and its coordination with the regional transmission planning process that also must be addressed to ensure that Commission-jurisdictional rates are just and reasonable.

1571. First, we find that local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders. The Commission has recognized the critical role that stakeholders serve in effective transmission planning,[3359] and in Order Nos. 890 and 1000, directed reforms to facilitate their meaningful participation in both local and regional transmission planning.[3360] However, the record demonstrates that existing transparency and coordination requirements in local transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.[3361] We further find that the

[3350] NOPR, 179 FERC ¶ 61,028 at P 399 (citing *S. Cal. Edison Co.,* 164 FERC ¶ 61,160 at P 33; *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136, at PP 12, 89 (2020); *PJM Interconnection, L.L.C.,* 173 FERC ¶ 61,242, at P 54 (2020)).

[3351] *Id.*

[3352] Dominion Initial Comments at 76 (citing NOPR, 179 FERC ¶ 61,028 at P 395 n.634); EEI Initial Comments at 40; Idaho Power Initial Comments at 12–13.

[3353] EEI Initial Comments at 40; *see also* Dominion Initial Comments at 76.

[3354] Idaho Power Initial Comments at 12–13.

[3355] Indicated PJM TOs Initial Comments at 41 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 426–561).

[3356] LS Power Initial Comments at 50–53 (citations omitted); NextEra Initial Comments at 54–56 (citations omitted). A number of commenters challenge the NOPR right-sizing proposal, including the proposal to permit a Federal right of first refusal for certain replacement facilities. We address those arguments below in the Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities section below.

[3357] Competition Coalition Initial Comments at 64.

[3358] Below, we clarify that the new transparency requirements do not apply to transmission facilities that are otherwise exempt from Order No. 890's transparency requirements, such as asset management projects. *See infra* Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

[3359] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 454 (''[C]ustomers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.''); Order No. 1000, 136 FERC ¶ 61,051 at P 152 (''[A]bsent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.'').

[3360] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152.

[3361] *E.g.,* OMS Initial Comments at 15 (''OMS members have varying levels of oversight and visibility into the utility-driven, local planning processes that are incorporated into the overall MISO transmission expansion plan.''); Concerned Scientists ANOPR Initial Comments at 24–31 (discussing challenges obtaining information to

Continued

absence of minimal standards or specified procedures to implement the transmission planning principles required by Order No. 890 contributes to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.

1572. The combined effect of these deficiencies is that stakeholders who wish to participate in transmission planning, at both the local and regional level, may not be able to effectively do so. More specifically, we find that, when engaging in the regional transmission planning process, stakeholders lack sufficient information about underlying local transmission needs and potential solutions that is necessary to ensure that the more efficient or cost-effective regional transmission solutions are identified, evaluated, and selected. Given the recognized importance of stakeholder participation in effective transmission planning, we find that reforms are needed to ensure that Commission-jurisdictional local and regional transmission planning processes remain just, reasonable, and not unduly discriminatory or preferential. Furthermore, we believe that reforms to better ensure more consistent implementation of the Order No. 890 transmission planning principles are timely and important in light of the significant investments in transmission infrastructure that now occur through local transmission planning processes.[3362]

1573. Second, we find that additional coordination between the local and regional transmission planning processes regarding replacement of aging infrastructure is needed. The record shows that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life. For example, we note that PJM estimated that roughly two-thirds of all PJM transmission system assets are more than 40 years old, with some transmission facilities approaching 90 years old.[3363] NYISO highlights that 80 percent of transmission lines in its footprint are at least 50 years old and are either being replaced or will soon need to be replaced.[3364] Replacing these transmission facilities will require substantial investment, which will directly affect Commission-jurisdictional transmission rates. For example, the California Commission notes that PG&E anticipates spending roughly $11 billion between 2022 and 2027 to address aging transmission infrastructure.[3365]

1574. However, because the Commission's existing requirements do not obligate transmission providers to share sufficient information regarding these replacement projects, transmission providers in the regional transmission planning process are not consistently evaluating whether those replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address transmission needs. We therefore find that the lack of a requirement for transmission providers in each transmission planning region to evaluate whether those replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address Long-Term Transmission Needs results in a regional transmission planning process that fails to identify opportunities to right-size planned in-kind replacement transmission facilities and may result in the development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.

1575. With respect to the claim by commenters that the Commission lacks jurisdiction to impose the proposed transparency and coordination requirements or that the Commission has not justified the requirements,[3366] we disagree. Consistent with Order Nos. 890 and 1000, the Commission has authority to establish requirements related to local transmission planning processes and the inputs to regional transmission planning processes.[3367] Our findings above are supported by substantial evidence in the record, and we address any concerns regarding our remedy to address the transparency and coordination deficiencies below.

1576. We also disagree with LS Power, Competition Coalition, and NextEra's arguments regarding whether the Commission properly demonstrated under FPA section 206 that existing rates are unjust, unreasonable, or unduly discriminatory or preferential in instituting a Federal right of first refusal for right-sized replacement transmission facilities.[3368] First, we clarify that the Commission is not finding that existing transmission planning processes are unjust, unreasonable, or unduly discriminatory or preferential due to a lack of a Federal right of first refusal for these facilities. Rather, we find here that transmission providers' OATTs are unjust and unreasonable due to the lack of right-sizing requirements that may lead to the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. As discussed above, the record demonstrates that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating, through the regional transmission planning process, whether those replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address transmission needs. As a result of this identified deficiency, we find that transmission providers' OATTs are unjust and unreasonable. We address LS Power, NextEra, and other commenters' concerns regarding the Commission's proposed replacement rate, including our findings regarding a Federal right of first refusal for right-sized replacement transmission facilities, below.

1577. Because we find that the Commission's existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206, that transmission providers

assess projects developed through local transmission planning processes) (citations omitted); New Jersey Commission ANOPR Initial Comments at 6–7 (discussing limited information and analysis provided regarding projects considered in local transmission planning) (citations omitted).

[3362] *See supra* The Overall Need for Reform section.

[3363] *See* PJM Interconnection, L.L.C., *The Benefits of the PJM Transmission System* 5 (2019), *https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf.* Moreover, AEP estimates that approximately 30 percent of its line miles and circuit breakers will need to be replaced over the next 10 years. *See* AEP, *Wolfe Utilities, Midstream, & Clean Energy Conference* 40 (Sept. 30, 2021), *https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/WolfeConferencePresentation093021.pdf.*

[3364] NYISO Initial Comments at 58.

[3365] California Commission Initial Comments at 110.

[3366] Dominion Initial Comments at 76; EEI Initial Comments at 40; Idaho Power Initial Comments at 12–13.

[3367] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 435 (''In order to limit the opportunities for undue discrimination . . . and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level.''); Order No. 1000, 136 FERC ¶ 61,051 at PP 68, 148, 152.

[3368] Competition Coalition Initial Comments at 64; LS Power Initial Comments at 51–53; NextEra Initial Comments at 54–56.

adopt, with certain modifications, the two reforms that the Commission identified in the NOPR: (1) enhance the transparency of local transmission planning processes; and (2) require transmission providers to evaluate whether transmission facilities that need replacing can be ''right-sized'' to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.[3369] We find that the first reform will result in transmission providers providing enhanced transparency for stakeholders while providing those same stakeholders with opportunities to more effectively engage in local and regional transmission planning processes. We find that the second reform will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Taken together, we find that these reforms will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

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

1. NOPR Proposal

1578. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.[3370] The Commission explained that transmission providers would be required to establish an iterative process that would provide stakeholders with meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process.[3371] The Commission proposed to require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before a transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.[3372]

1579. Specifically, the Commission proposed to require transmission providers in each transmission planning region, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers that are members of the transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, the Commission proposed to require that, no fewer than 25 calendar days after the Needs Meeting, transmission providers that are members of the transmission planning region convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). The Commission also proposed to require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.[3373]

1580. The Commission preliminarily found that these proposed requirements will result in needed additional transparency into local transmission planning processes, which inform the regional transmission planning process in a transmission planning region.[3374]

2. Comments

a. Interest in Enhanced Transparency of Local Transmission Planning Inputs

1581. Many commenters support the NOPR proposal.[3375] ITC argues that the Commission's proposed transparency requirements strike an appropriate balance between the need for oversight and the need to timely address asset management needs.[3376] Southeast PIOs state that closer coordination between the regional and local transmission planning processes would help to ensure that the local process does not dull the effectiveness of the regional process.[3377] Vermont State Entities support enhancing transparency and visibility of local transmission planning processes and coordinating with Long-Term Regional Transmission Planning and other processes, including the generator interconnection process.[3378] City of New Orleans Council states that increased transparency, collaboration, and coordination between the regional and local transmission planning processes will result in more efficient local transmission development.[3379] OMS asserts that enhanced transparency will enable retail regulators to more effectively participate in identifying the best set of projects to meet both local and regional needs.[3380]

1582. Colorado Consumer Advocates state that the Commission must ensure that transmission providers maintain coordinated, open, and transparent transmission planning processes on both a local and regional level that meet stakeholder needs.[3381] Interwest asserts that the NOPR proposal is needed to incentivize the coordination of generation and resource planning and transmission planning beyond state lines, adding that transparency measures, such as a process for information sharing, could allow customers or stakeholders to evaluate or replicate the findings from transmission

[3369] NOPR, 179 FERC ¶ 61,028 at PP 400–403.

[3370] NOPR, 179 FERC ¶ 61,028 at P 400.

[3371] *Id.*

[3372] *Id.*

[3373] *Id.* P 401.

[3374] *Id.* P 402.

[3375] *See* AEE Initial Comments at 3; AEP Reply Comments at 10; APPA Initial Comments at 47; Breakthrough Energy Initial Comments at 19; Center for Biological Diversity Initial Comments at 28; Certain TDUs Initial Comments at 13; City of New Orleans Council Initial Comments at 11; Clean Energy Associations Initial Comments at 36; Clean Energy Buyers Initial Comments at 33; Colorado Consumer Advocates Initial Comments at 30–31; Cross Sector Representatives Supplemental Comments at 1; Exelon Initial Comments at 3, 51–52; Indicated PJM TOs Initial Comments at 40; Interwest Initial Comments at 17–18; ITC Initial Comments at 45–47; National and State Conservation Organizations Initial Comments at 2; New York Transco Initial Comments at 1; NextEra Initial Comments at 66–67; Northwest and Intermountain Initial Comments at 20; OMS Initial Comments at 16; PJM States Initial Comments at 4–6; Resale Iowa Initial Comments at 8; Resale Iowa Reply Comments at 5; SEIA Initial Comments at 25–26; Shell Initial Comments at 34; Southeast PIOs Initial Comments at 54–55; Vermont State Entities Initial Comments at 10.

[3376] ITC Initial Comments at 45–47 (citations omitted).

[3377] Southeast PIOs Initial Comments at 54–55.

[3378] Vermont State Entities Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

[3379] City of New Orleans Council Initial Comments at 11.

[3380] OMS Initial Comments at 16.

[3381] Colorado Consumer Advocates Initial Comments at 17, 20–21.

providers and reduce after-the-fact disputes regarding allocated costs.[3382]

1583. Exelon and Indicated PJM TOs note that the NOPR proposal mirrors PJM TOs' local transmission planning process.[3383] Indicated PJM TOs state that the NOPR proposal will help to ensure the coordination of local and regional transmission planning while preserving transmission owner responsibility for local transmission planning.[3384] Indicated PJM TOs state that the PJM Attachment M–3 process avoids duplication of projects between local and regional transmission planning processes.[3385] Clean Energy Associations state that each transmission planning region should have the opportunity to regularly review local transmission planning criteria for consistency with regional transmission planning, as PJM's manuals require.[3386]

1584. Clean Energy Buyers state that existing local transmission planning has not met expectations for openness, coordination, and transparency, and that the NOPR proposal will help remedy such deficiencies and better identify cost-effective transmission projects.[3387] Northwest and Intermountain agree that the Commission should reform local transmission planning processes to enhance transparency and provide meaningful opportunities for public input.[3388] Similarly, Resale Iowa asserts that MISO's stakeholder processes do not address local transmission planning issues, especially those related to asset management, end-of-life, and other forms of local transmission planning that are exempt from Order No. 890's transmission planning requirements. Thus, Resale Iowa contends, its members believe they must bear the cost of new or upgraded transmission facilities without the opportunity to discuss less costly alternatives.[3389]

1585. National and State Conservation Organizations suggest that early and consistent community engagement are key elements to successful development and timely completion of transmission projects, as the voices and concerns of affected local communities must be heard and acted upon to prevent environmental injustices and environmental damage.[3390] WE ACT states that, in addition to coordination with state entities, there must also be meaningful engagement and robust input from affected and overburdened communities so that states and transmission providers are aware of the potential harms of siting transmission projects in environmental justice communities. WE ACT recommends that the Commission, its Office of Public Participation, state officials, and transmission providers familiarize themselves with several key documents relating to environmental justice to ensure meaningful community engagement and to inform comprehensive environmental justice analyses to reduce or eliminate undue burdens.[3391]

b. Suggested Modifications to the NOPR Proposal

1586. Some commenters support the NOPR proposal, but also suggest modifications to make it more effective or request that the Commission provide flexibility for transmission planning regions to determine the best manner to meet the requirements.[3392] NARUC requests flexibility for transmission planning regions to determine the timeline for stakeholder processes.[3393] NRECA requests that the Commission allow transmission planning regions that currently have transparent processes to maintain them.[3394]

1587. TANC encourages the Commission to provide regional flexibility by allowing transmission providers to propose on compliance alternative frameworks for consideration of local transmission plans in the regional transmission planning process and allow transmission planning regions to consider the burden versus benefit of such as a requirement to maximize transparency and project efficiencies.[3395]

1588. NESCOE contends that aspects of the proposal are too prescriptive, such as the Commission dictating the number of stakeholder meetings. However, NESCOE states that enhanced transparency could help states and ratepayers better understand proposed transmission facilities and the costs associated with them.[3396] NESCOE states that stakeholders should have meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process, asserting that transmission owners in ISO–NE currently do little more than present their proposals for in-kind replacements of existing transmission infrastructure to ISO–NE's Planning Advisory Committee.[3397]

1589. ACORE states that the proposed stakeholder involvement in local transmission planning is beneficial but that the NOPR proposal lacks clarity on whether transmission providers must consider local transmission projects alongside other options in Long-Term Regional Transmission Planning.

1590. Joint Consumer Advocates argue that, while the NOPR proposal will increase transparency, it will not address the inability of consumer advocates to meaningfully review planning inputs or models because the inputs are not maintained in a format that enables stakeholders to review them, understand the assumptions, or replicate the transmission planning results, as contemplated in Order No. 890.[3398] Pine Gate recommends that the Commission require that transmission providers make available to stakeholders information about the local transmission planning process for review and comment prior to the finalization or approval of the local transmission plan.[3399]

[3382] Interwest Initial Comments at 17–18. As an example, Interwest cites WestConnect's Colorado Coordinated Planning Group, which conducts transmission planning through task forces and work groups consisting of stakeholders. *Id.*

[3383] Exelon Initial Comments at 3–4, 51–52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)); *see* Indicated PJM TOs Initial Comments at 42–43.

[3384] Indicated PJM TOs Initial Comments at 42–43.

[3385] *Id.* at 42.

[3386] Clean Energy Associations Initial Comments at 37 (citing PJM Manual 14B, section 1.1 Planning Process Work Flow).

[3387] Clean Energy Buyers Initial Comments at 33.

[3388] Northwest and Intermountain Initial Comments at 20.

[3389] Resale Iowa Reply Comments at 4–5.

[3390] National and State Conservation Organizations Initial Comments at 2.

[3391] WE ACT Initial Comments at 5–6 (citing U.S. Env't Prot. Agency, *Promising Practices for EJ Methodologies in NEPA Reviews* (Mar. 2016), *https://www.epa.gov/environmentaljustice/ej-iwg-promising-practices-ej-methodologies-nepa-reviews*; U.S. Env't Prot. Agency, *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* (June 2016), *https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf*; *The Principles of Environmental Justice (EJ),* Energy Justice Network, *https://www.ejnet.org/ej/principles.pdf*; *Jemez Principles of Democratic Organizing,* Energy Justice Network, *https://www.ejnet.org/ej/jemez.pdf*).

[3392] *See* ACORE Initial Comments at 18–19; AEP Initial Comments at 7, 40–41, 43–44; Ameren Initial Comments at 46–47; NARUC Initial Comments at 58–59; NESCOE Initial Comments at 77–78; North Carolina Commission and Staff Initial Comments at 18–20; NRECA Initial Comments at 65–66; NYISO Initial Comments at 9, 57–58; TANC Initial Comments at 11; WE ACT Initial Comments at 5–6; WIRES Initial Comments at 8–10.

[3393] NARUC Initial Comments at 58–59 (citing NOPR, 179 FERC ¶ 61,028 at PP 400–401).

[3394] NRECA Initial Comments at 65–66; *see also* Ameren Initial Comments at 46 (citing Ameren ANOPR Initial Comments at 20–21).

[3395] TANC Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at PP 400, 402).

[3396] NESCOE Initial Comments at 77–78 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

[3397] *Id.;* NESCOE Reply Comments at 6 (citation omitted).

[3398] Joint Consumer Advocates Initial Comments at 21–22.

[3399] Pine Gate Initial Comments at 49–50.

c. Concern With the NOPR Proposal

1591. Several commenters state that they oppose or have concerns with the NOPR proposal.[3400] Ohio Commission Federal Advocate argues that the NOPR proposal is of limited value given that it does not require a more comprehensive review of local transmission projects; instead, these projects will continue to be chosen, designed, and approved by the transmission owner.[3401] Similarly, American Municipal Power states that new transmission projects that expand or enhance the transmission grid and have regional benefits should be planned by the regional transmission entity and not by individual transmission owners. Further, American Municipal Power asserts that use of the PJM Attachment M–3 process, which American Municipal Power contends the NOPR ''essentially'' proposes to require nationwide, has resulted in additional balkanization of the transmission planning process, has increased the problem of planning based on individual transmission owners' criteria for determining need, and has disenfranchised PJM as the regional transmission planner.[3402]

1592. Relatedly, Pennsylvania Commission states that enhancing transparency in local transmission planning is a laudable goal but notes that the proposal will not enhance PJM's process because the NOPR proposal adopts the existing PJM Attachment M–3 process.[3403]

1593. Several commenters argue that the existing regional transmission planning process in their transmission planning region is already transparent and therefore oppose the NOPR proposal.[3404] New York TOs assert that New York's regional and local transmission planning processes almost fully satisfy the proposed requirements and, as such, the Commission should allow NYISO to retain these processes.[3405] MISO argues that the additional requirements proposed in the NOPR are not needed in an RTO such as MISO with a fully developed, open, and transparent transmission planning process in effect.[3406] MISO TOs agree, stating that MISO's existing processes provide for transparency in local transmission planning through subregional planning meetings, published materials, and workshops throughout the transmission planning process.[3407]

1594. CAISO states that the Commission should not disrupt existing processes that are working efficiently, arguing that its transmission planning process already considers both local and regional assumptions, needs, and solutions as part of a single integrated process.[3408] PG&E agrees that the NOPR proposal is unnecessary for California utilities and CAISO because many CAISO transmission owners already have extensive stakeholder programs. Therefore, PG&E states, the Commission should clarify that transmission providers are not required to enhance the transparency of local transmission planning processes where such transparent processes already exist.[3409]

1595. In addition, PG&E argues that the Commission should revise the NOPR proposal to state that the proposed enhancements to the local transmission planning process should not apply to asset management projects, including in-kind replacements, that are outside the scope of Order No. 890.[3410] PG&E asserts that including asset management projects would significantly increase the volume and complexity of regional and local transmission planning and potentially delay needed repairs and maintenance. PG&E further states that all of PG&E's asset replacement projects are already scrutinized through the annual update to its formula transmission rate.[3411]

1596. Eversource contends that the current local transmission planning process in New England, which is based on the principles in Order No. 890, is largely consistent with the Commission's proposed transparency principles and has worked well.[3412] Similarly, APS states that it currently uses its local transmission plans in the base model assumptions for its regional transmission planning process and provides stakeholders with an opportunity for input twice a year in public meetings as required by Order No. 890.[3413]

1597. Some commenters request that the Commission adopt a less prescriptive reform that outlines principles or goals for transparency and allow each transmission provider to either explain how its existing local transmission planning process already complies with those principles or propose targeted modifications to bring its existing process into compliance with the new requirements.[3414] New York TOs note that efforts to improve transparency between local and regional transmission planning are beginning in NYISO, and they recommend that the Commission allow NYISO and New York TOs to demonstrate on compliance how any resulting enhancements will meet or exceed any new requirements.[3415] Vermont Electric and Vermont Transco suggest that the Commission adopt a performance-based approach under which the Commission would specify expectations for transparency in local transmission planning processes and then allow transmission providers to determine how they will achieve those goals within longer timelines.[3416]

[3400] *See* American Municipal Power Initial Comments at 13–25; APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial Comments at 7, 47–51; California Water Initial Comments at 5–8; DC and MD Offices of People's Counsel Initial Comments at 6–7; Dominion Initial Comments at 69–70; EEI Initial Comments at 40; Eversource Initial Comments at 47–49; Idaho Power Initial Comments at 12–13; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 28–31; National Grid Initial Comments at 39–40; New York TOs Initial Comments at 16–17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 15–18; PPL Initial Comments at 35–36; Xcel Initial Comments at 16–17.

[3401] *See* Ohio Commission Federal Advocate Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 16)).

[3402] American Municipal Power Initial Comments at 17; *see* American Municipal Power Supplemental Comments at 1, 6 (citations omitted).

[3403] Pennsylvania Commission Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 at PP 399–400).

[3404] APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial Comments at 46–50; Dominion Initial Comments at 69; Eversource Initial Comments at 46–49; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16–17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16–18.

[3405] New York TOs Initial Comments at 7.

[3406] MISO Initial Comments at 84–85.

[3407] MISO TOs Initial Comments at 29–31 (citing MISO Business Practice Manual, Transmission Planning, BPM–20, section 4.1; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § I.C.9; MISO, *Subregional Planning Meeting, https://www.misoenergy.org/engage/committees/subregional-planning-meeting/*; *Midwest Indep. Transmission Sys. Operator, Inc.,* 142 FERC ¶ 61,215, at PP 80, 114 (2013), *order on reh'g,* 144 FERC ¶ 61,020 (2013), *order on reh'g & compliance,* 147 FERC ¶ 61,127 (2014), *aff'd sub nom. MISO Transmission Owners* v. *FERC,* 819 F.3d 329 (7th Cir. 2016)).

[3408] CAISO Initial Comments at 47–50 (citations omitted).

[3409] PG&E Initial Comments at 15–18.

[3410] *Id.* at 15–16 (citing *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec.,* 164 FERC ¶ 61,161 at P 66).

[3411] PG&E Reply Comments at 6–7.

[3412] Eversource Initial Comments at 46–47 (citing *ISO New England, Inc.,* Transmittal, Docket No. OA08–58 (filed Dec. 7, 2007)).

[3413] APS Initial Comments at 12 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 257–258, 451).

[3414] *See* Avangrid Initial Comments at 15; EEI Initial Comments at 40; Eversource Initial Comments at 48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84; MISO TOs Initial Comments at 31; National Grid Initial Comments at 39; New York TOs Initial Comments at 7, 16–17; Xcel Initial Comments at 17.

[3415] *See* New York TOs Initial Comments at 6–7, 16–17 (citations omitted).

[3416] Vermont Electric and Vermont Transco Initial Comments at 5.

1598. Several commenters argue that the NOPR proposal is too prescriptive or may interfere with existing processes.[3417] Eversource states that, if the Commission adopts a more prescriptive approach to local transmission planning, it could conflict with existing, state-jurisdictional planning processes for local transmission projects, creating barriers to distribution facility upgrades that are needed to support expanded use of distributed energy resources and load growth from electrification.[3418] Dominion cautions against adding more process when transmission providers already participate in extensive local transmission planning processes that consider Long-Term Regional Transmission Planning and stakeholder positions.[3419] Avangrid agrees, asserting that the NOPR proposal could override existing processes that have been established over years of stakeholder consensus building.[3420] PPL and American Municipal Power state that the NOPR proposal may not be appropriate for all transmission planning regions and may interfere with efficient and well-functioning local transmission planning.[3421]

1599. Certain commenters also argue that the NOPR proposal is unduly burdensome.[3422] APS argues that the NOPR proposal could delay local transmission planning and prevent APS from providing necessary services.[3423] National Grid asserts that the NOPR proposal ignores the reality that local transmission planning processes address different needs than the regional transmission planning process. National Grid argues that the proposal will introduce delay and uncertainty in both the local and regional transmission planning processes, disrupting currently effective procedures at a time when participants in the regional transmission planning process should be focused on Long-Term Regional Transmission Planning.[3424]

1600. In addition, National Grid argues that the NOPR proposal will complicate transmission planning because individual transmission providers in each transmission planning region will need to integrate their local transmission planning efforts into the regional transmission planning process. Further, National Grid states that in multi-state RTO/ISO transmission planning regions, it could also lead to second guessing individual state policies as part of the regional transmission planning process. National Grid also avers that regional transmission planners, such as NYISO and ISO–NE, may not have visibility into the operation of lower voltage local transmission facilities and therefore may not have the expertise that is needed to consider local transmission needs as part of the regional transmission planning process.[3425]

d. *Specific Stakeholder Meeting Requirements*

1601. With respect to the length of time between stakeholder meetings, some commenters state that the 25-day minimum period between meetings in the NOPR proposal is too short.[3426] PIOs state the Commission should require transmission providers to submit local transmission planning information, including information concerning planned local transmission projects, with enough time for the regional transmission planning process to effectively find, propose, approve, and construct cost-effective and beneficial regional alternatives where appropriate.[3427]

1602. American Municipal Power contends that the NOPR proposal fails to identify whether and when transmission providers must provide information in advance of the three meetings. Moreover, American Municipal Power argues, 25 days between meetings is too short, even assuming all of the models, criteria, and needs are shared with stakeholders sufficiently in advance. Further, American Municipal Power states that the time between the Needs and Solutions Meetings should be based on the time required for transmission providers to incorporate comments received during the Needs Meeting and develop responses.[3428]

1603. Eversource argues that the proposed meeting schedules are not workable in New England, where regional transmission planning studies focus on sub-areas of the transmission system and proceed on different timelines. Moreover, Eversource contends that it is not feasible in New England to have a three-meeting process that aligns with ISO–NE's annual transmission planning cycle because no such annual planning cycle exists.[3429]

1604. Dominion, Eversource, and Xcel state that the three separate stakeholder meetings to review assumptions, needs, and solutions are unnecessary and will increase workload without any benefit.[3430] Xcel contends that a single meeting that addresses the transparency requirements of Order Nos. 890 and 1000, as well as any requirements from the final order, would be more efficient than the NOPR proposal.[3431] NESCOE asserts that the final order should not dictate the number of stakeholder meetings.[3432] MISO states that the Commission should allow each transmission planning region to determine the timing of the iterative meetings, as well as the specific information to be covered at the meetings.[3433]

1605. TAPS states that the Commission should require transmission providers to post their criteria, models, and assumptions so that stakeholders can evaluate or replicate their findings. Moreover, TAPS argues, the Commission should require that transmission providers distribute this information ''sufficiently in advance'' (and not just ''in advance,'' as the NOPR proposed) of each meeting to allow stakeholders to review and evaluate the information.[3434] Finally, TAPS states that a second Solutions Meeting would provide a meaningful opportunity to consider alternatives.[3435]

1606. Likewise, American Municipal Power recommends that the Commission require a minimum of two Solutions Meetings, with the transmission provider presenting the solutions at the first meeting and the final solution, including alternatives considered, at the second. Further, American Municipal Power recommends that the first Solutions Meeting be no sooner than 90 days after the Needs Meeting and the second

[3417] Avangrid Initial Comments at 13; CAISO Initial Comments at 7–8, 47, 50; Dominion Initial Comments at 70; Eversource Initial Comments at 47–48; MISO Initial Comments at 86; PG&E Initial Comments at 17–18; PPL Initial Comments at 36; Xcel Initial Comments at 16–17.

[3418] Eversource Initial Comments at 49.

[3419] Dominion Initial Comments at 69–70.

[3420] Avangrid Initial Comments at 13.

[3421] American Municipal Power Initial Comments at 16; PPL Initial Comments at 36.

[3422] *See* Dominion Initial Comments at 68; Eversource Initial Comments at 49; National Grid Initial Comments at 39–40; Xcel Initial Comments at 16–17.

[3423] APS Initial Comments at 13.

[3424] National Grid Initial Comments at 39–40.

[3425] *Id.*

[3426] American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; PIOs Initial Comments at 51–54; TAPS Initial Comments at 6, 62.

[3427] PIOs Initial Comments at 51–52, 54 (citing PIOs ANOPR Initial Comments at 92–94; Concerned Scientists ANOPR Initial Comments at 24–31).

[3428] American Municipal Power Initial Comments at 24.

[3429] Eversource Initial Comments at 47.

[3430] Dominion Initial Comments at 68; Eversource Initial Comments at 47–48; Xcel Initial Comments at 17.

[3431] Xcel Initial Comments at 16–17.

[3432] NESCOE Initial Comments at 78 (citation omitted).

[3433] MISO Initial Comments at 84.

[3434] TAPS Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

[3435] *Id.* at 62.

Solutions Meeting no sooner than 30 days after the first Solutions Meeting. To the extent the Commission does not require a second Solutions Meeting, American Municipal Power recommends that it require transmission providers to provide additional clarity regarding how alternatives were developed and why they were not selected during the single Solutions Meeting.[3436]

1607. While PJM States support requiring Assumptions, Needs, and Solutions Meetings as part of local transmission planning processes, similar to PJM's existing Attachment M–3 process, they express concern that PJM's process is not sufficiently responsive and that the growth of transmission-related costs in PJM is occurring without effective oversight.[3437] PJM States reference PJM's requirement that transmission providers provide information on their local transmission plan and consider any comments received, but state that they are not required to ''meaningfully respond to, engage with, or incorporate'' these comments.[3438]

1608. California Commission notes that the key elements of the California stakeholder processes that may be relevant for the Commission to consider including in a final order to increase transparency into local transmission planning include: (1) detailed project and capital expenditure data; (2) ample time to review proposed capital forecasts; (3) the ability for stakeholders to issue data requests and receive responses; (4) in-depth stakeholder meetings; and (5) consideration of stakeholder comments.[3439]

1609. New England for Offshore Wind argues that all transmission planning processes should include transparency into the evaluation of alternative options that could optimize the performance of renewable energy, as well as justification of proposed transmission projects based on how they compare to no action alternatives.[3440] NRG encourages the Commission to require that the local transmission planning process produce an estimated rate impact for each year if the local transmission plan were to be executed.[3441]

1610. Several commenters contend that transmission providers should be required to respond to comments and questions submitted by stakeholders in the local transmission planning process.[3442] PJM States raise the same issue but look to the relevant RTOs/ISOs to resolve them.[3443]

1611. American Municipal Power and DC and MD Offices of People's Counsel state that transmission providers are not obligated to respond to stakeholder questions, which, when considered alongside the other barriers to effective participation, creates unnecessary barriers to open communication, is not just and reasonable, and is unduly discriminatory.[3444] American Municipal Power further asserts that comparability principles require transmission providers to consider transmission customers' comments in order to meet their needs and to treat similarly situated customers comparably while conducting transmission system planning.[3445] However, PJM and Indicated PJM TOs disagree that stakeholder comments are being ignored in PJM's Attachment M–3 process.[3446]

1612. TAPS states that dispute resolution on criteria, assumptions, needs, and proposed solutions should be available if stakeholder comments are ignored.[3447] TAPS asserts that the Commission should include such provisions in any final order or clarify that they are already encompassed in the Commission's transparency proposal.[3448]

e. Additional Issues

1613. Pattern Energy and American Municipal Power state that the NOPR proposal does not go far enough in ensuring stakeholder access to transmission planning data from the local transmission planning processes and propose additional requirements to make certain information more readily available, subject to execution of a CEII non-disclosure agreement.[3449] Similarly, Pattern Energy states that continued stakeholder access to the source data used in transmission modeling by transmission providers is essential to ensure fair and reasonable outcomes in any transmission planning process.[3450] PPL requests that the Commission clarify that confidential or sensitive information will be protected under the NOPR proposal in the local transmission planning processes as they currently are in PJM.[3451]

1614. Certain TDUs state that the Commission should require transmission providers to coordinate with load-serving entities to transfer data and information and increase transparency in the stakeholder process.[3452] ACEG recommends that the Commission require minimum data transparency standards in the local transmission planning processes, drawing on MISO's and SPP's cost recording and tracking processes for transmission projects approved through their regional transmission planning processes.[3453] Maryland Energy Administration asserts that additional reforms beyond those proposed in the NOPR are needed to support transparency and better incorporate stakeholder contributions in local transmission planning processes.[3454] California Water recommends that the Commission allow data requests, similar to the opportunity for data requests in the SoCal Edison and PG&E stakeholder review processes, which ensure that stakeholders can participate and that transmission providers exercise good faith efforts to respond.[3455]

1615. American Municipal Power requests that the Commission direct transmission providers to provide detailed information consisting of more than generic or high-level network models, along with power flow models and power system analyses used in their

[3436] American Municipal Power Initial Comments at 24–25.

[3437] PJM States Initial Comments at 4–5 (citing PJM, *2021 Regional Transmission Planning Expansion Plan* 290 (Mar. 2022), *https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx*).

[3438] *Id.* at 6 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0), section (c) 1–6).

[3439] California Commission Initial Comments at 112–113.

[3440] New England for Offshore Wind Initial Comments at 6.

[3441] NRG Initial Comments at 7, 36.

[3442] *See* American Municipal Power Initial Comments at 18–19; California Commission Initial Comments at 112–113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky Commission Chair Chandler Initial Comments at 22; Northwest and Intermountain Initial Comments at 20–21; TAPS Initial Comments at 62.

[3443] PJM States Initial Comments at 6.

[3444] *See* American Municipal Power Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 6–7.

[3445] American Municipal Power Initial Comments at 19.

[3446] Indicated PJM TOs Reply Comments at 4, 18–19 (citations omitted); PJM Reply Comments at 13–15 (citing American Municipal Power Initial Comments at 19).

[3447] TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501–503).

[3448] *Id.*

[3449] *See* American Municipal Power Initial Comments at 22; Pattern Energy Initial Comments at 30–31.

[3450] Pattern Energy Initial Comments at 30–31.

[3451] PPL Initial Comments at 36.

[3452] Certain TDUs Initial Comments at 18.

[3453] ACEG Initial Comments at 56 (citing Johannes Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* 26 (Apr. 2019)).

[3454] *See* Maryland Energy Administration Reply Comments at 2–3 (citations omitted).

[3455] California Water Initial Comments at 7–8 (citing *S. Cal. Edison,* Filing, App. XII, ER19–1553–000, at section 2.2 (filed July 2, 2020); *Pac. Gas & Elec. Co.,* Filing, App. IX, ER19–13–001, at section 3.2 (filed Mar. 31, 2020)).

local transmission planning.[3456] According to American Municipal Power, to allow stakeholders to evaluate the outputs of transmission providers' studies—*i.e.,* the identified transmission needs—on their own, transmission providers must be required to provide the models.[3457] Furthermore, American Municipal Power argues, the Commission should require transmission providers to provide information on how assets have been prioritized for replacement, how the replacement versus maintenance decision is made, how assets rank relative to other assets on the system, and the system average values.[3458]

1616. Several commenters state that the NOPR proposal does not go far enough to protect customers' interests and suggest the addition of more process, more oversight, more monitoring (including establishing an independent transmission monitor), or more prudence reviews.[3459] According to PIOs, transmission providers have incentives to avoid independent transmission planning processes because local transmission projects are presumed to be prudent, avoid competition, and receive high rates of return. PIOs state that the Commission should reduce the rate of return for local transmission projects and issue a rule or policy statement that puts the burden of proof on transmission providers to demonstrate that the cost of a proposed transmission project is just and reasonable.[3460]

1617. Joint Consumer Advocates state that, while the NOPR proposal is an improvement, more needs to be done to address the imbalance between consumer advocates and incumbent transmission owners. Therefore, Joint Consumer Advocates assert, the Commission should authorize the creation of an independent transmission monitor to evaluate the effective coordination of local transmission projects with more holistic transmission planning to identify the most efficient or cost-effective approach to meeting local, regional, and interregional transmission needs.[3461] Relatedly, California Commission and Colorado Consumer Advocates suggest that the Commission give independent transmission monitors the responsibility to evaluate stakeholder comments, independently analyze whether there are potentially more efficient and cost-effective alternative transmission solutions to meet identified transmission needs, and make a recommendation.[3462] Potomac Economics argues that the Commission's transparency goals likely cannot be met without an independent transmission monitor.[3463]

1618. Some commenters opine on whether the regional transmission planning process should assume an expanded role in reviewing or approving identified local transmission projects.[3464] In addition, NARUC recommends that the Commission allow the proposed stakeholder review process to apply to repair and replacement projects that do not expand the capacity of the transmission system, or do so only incidentally, in particular those that are forecast to cost $3 million or more. NARUC asserts that, limiting the reforms to local transmission planning may exclude review of these projects, which currently comprise half of investor-owned utilities' transmission spending in the RTOs/ISOs. Further, NARUC urges the Commission to allow these projects, along with local transmission projects, to be reviewed and approved as part of the regional transmission planning process.[3465] California Commission agrees, stating that there should be more external scrutiny of such projects to reduce incumbent utilities' existing perverse incentive to overinvest in these types of projects due to their lack of external review.[3466]

1619. PJM States call on RTOs/ISOs to go beyond evaluating whether local transmission projects ''do no harm'' by actively taking a stance on such projects, discussing how this stance was reached, and by proposing transmission projects that may be the most cost-effective.[3467] However, PJM States ask the Commission to explicitly avoid impinging on state-jurisdictional processes.[3468]

1620. DC and MD Offices of People's Counsel and American Municipal Power assert that the remedy for the current lack of a requirement to incorporate or respond to stakeholder feedback in the local transmission planning process is an empowered regional transmission planner that is independent and incorporates meaningful participation from all stakeholders beginning with the determination of any transmission needs through the project selection phase.[3469] Relatedly, Ohio Consumers state that the NOPR proposal leaves sole discretion in selection of transmission projects and the costs of the projects to transmission providers.[3470]

1621. However, some commenters defend the separation between local and regional transmission planning processes.[3471] For instance, AEP disagrees that transmission providers seek to build local transmission projects to circumvent the regional transmission planning process.[3472] According to AEP, local and regional transmission planning processes are not interchangeable because most local transmission facilities directly serve load and local utilities must address local needs when those needs are not addressed by a regional transmission facility in a cost-effective manner.[3473] Nevertheless, AEP states, there can be an effective and efficient intersection between local and regional transmission planning, citing PJM's open and transparent local transmission planning process that requires coordination with the regional transmission planning process and in which PJM is an active participant.[3474] Similarly, WIRES states that there are good reasons for maintaining a distinction between regional and local transmission planning, noting that the regional transmission planning process is directed toward addressing certain

[3456] American Municipal Power Initial Comments at 20–21.

[3457] *Id.* at 21.

[3458] *Id.* at 22–23.

[3459] California Commission Initial Comments at 111–112 & n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25–29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23–24; OMS Initial Comments at 16–17; Pattern Energy Initial Comments at 31–34; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 51–52; PJM States Initial Comments at 4–6; TAPS Initial Comments at 61–62; US DOJ and FTC Initial Comments at 20–21.

[3460] PIOs Initial Comments at 52–53.

[3461] Joint Consumer Advocates Initial Comments at 26–29 (citations omitted).

[3462] California Commission Initial Comments at 111–112; Colorado Consumer Advocates Initial Comments at 31.

[3463] *See* Potomac Economics Initial Comments at 6.

[3464] *See* American Municipal Power Reply Comments at 3–7; California Commission Initial Comments at 108–110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60–61; Ohio Consumers Reply Comments at 17–18; PJM States Initial Comments at 6–7.

[3465] NARUC Initial Comments at 60–63 (citations omitted).

[3466] California Commission Initial Comments at 109–110 (citations omitted).

[3467] PJM States Initial Comments at 6–7 (citation omitted).

[3468] *Id.* at 7.

[3469] American Municipal Power Reply Comments at 3–7 (citations omitted); DC and MD Offices of People's Counsel Initial Comments at 7.

[3470] Ohio Consumers Reply Comments at 18.

[3471] AEP Reply Comments at 6–7; MISO Reply Comments at 27; PG&E Reply Comments at 4–9; WIRES Initial Comments at 9.

[3472] AEP Reply Comments at 6–7 (citing AEE Initial Comments at 38; PIOs Initial Comments at 8–9; Resale Iowa Initial Comments at 7–8; US DOJ and FTC Initial Comments at 7).

[3473] *Id.* at 2–3.

[3474] *Id.* at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)).

reliability, economic criteria, and public policy initiatives, not the additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that are the focus of local transmission planning.[3475]

1622. Eversource states that, if the Commission decides to require a more prescriptive local transmission planning process, it should clarify that the process applies only to upgrades that are developed primarily to increase the capacity of the local transmission system, and not to upgrades that are incidental to state-jurisdictional distribution system planning or other unique local requirements.[3476]

1623. MISO defends the transparency of local transmission planning in MISO by stating that commenters who criticize existing local transmission planning processes ''ignore the open, transparent process in effect, and fail to recognize the ongoing need for near-term planning.'' [3477] MISO states that local and regional transmission planning are complementary and that ''near-, mid- and long-term planning work in concert.'' [3478] MISO contends that its existing process includes extensive stakeholder involvement that ensures that issues are identified and alternatives are considered.[3479]

1624. PG&E opposes comments in favor of removing the role of local transmission planning from local transmission owners, as well as requests to expand the NOPR proposal to apply to asset management projects. PG&E notes that California Commission has not provided any evidence that RTOs/ISOs are currently unable to adequately handle the regional and local transmission planning processes.[3480]

3. Commission Determination

1625. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to enhance the transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through the local transmission planning process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs. For each of these three categories of local transmission planning information, and as discussed further below, transmission providers must identify and publicly post the information identified below, then conduct publicly-noticed stakeholder meetings to provide an opportunity for comment on the information both before and after the stakeholder meetings, as part of the regional transmission planning process. In response to comments from PG&E,[3481] we clarify that this requirement applies only to local transmission planning that is within the scope of Order No. 890 and is therefore already subject to Order No. 890 transparency requirements. As such, this requirement does not apply to asset management projects.[3482] However, nothing in this final order prevents transmission providers from choosing to apply these requirements to asset management projects.

1626. In complying with this requirement, transmission providers must establish an iterative process that ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process. To provide the needed transparency and opportunities for stakeholder participation, we require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings per regional transmission planning cycle concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1627. Specifically, we adopt the NOPR proposal to require that, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, no fewer than 25 calendar days after the Needs Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). Additionally, we require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.

1628. In addition to these requirements, we modify the NOPR proposal to also require transmission providers to publicly post the meeting materials no fewer than five calendar days prior to each of the three publicly-noticed stakeholder meetings to allow time for stakeholders to review materials in advance of each meeting. Also, we require that transmission providers allow for a period of no fewer than 25 calendar days following the Solutions Meeting to review and consider stakeholder feedback on the local transmission solutions identified to meet the local transmission needs before the local transmission plan can be incorporated in the transmission planning region's planning models. Requiring this minimum 25 calendar day period is consistent with Order No. 1000, where the Commission stated that the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.[3483] Lastly, we require that transmission providers must respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate in these three required stakeholder meetings.

[3475] WIRES Initial Comments at 9 (citing Charles River Associates, *The Value of Local Transmission Planning* 9, 13 (Dec. 2021), *https://wiresgroup.com/wp-content/uploads/2021/12/Value-of-Local-Transmission-Planning-report-WIRES-CRA.pdf*).

[3476] Eversource Initial Comments at 49.

[3477] MISO Reply Comments at 27 (citing PIOs Initial Comments at 32).

[3478] *Id.*

[3479] *Id.*

[3480] PG&E Reply Comments at 4–9 (citations omitted).

[3481] PG&E Initial Comments at 17 (citing *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec.,* 164 FERC ¶ 61,161 at P 66).

[3482] *See S. Cal. Edison Co.,* 164 FERC ¶ 61,160 at PP 30–40; *Cal. Pub. Utils. Comm'n* v. *Pac. Gas. & Elec. Co.,* 164 FERC ¶ 61,161 at PP 65–74 (finding that Order No. 890's local transmission planning requirements do not apply to asset management projects that do not increase capacity or do so incidentally).

[3483] Order No. 1000, 136 FERC ¶ 61,051 at P 153 (citing Order No. 890, 118 FERC ¶ 61,119 at P 454).

1629. We find that establishing a standard baseline of transparency into transmission providers' local transmission planning processes will ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning assumptions, needs, and solutions that are used as inputs to the regional transmission planning process. We expect that this additional transparency will help reduce the possibility that transmission providers will develop local transmission facilities without adequately considering whether there is a more efficient or cost-effective regional transmission solution that could address their local transmission needs. This additional transparency will enable transmission providers to satisfy their requirements for regional transmission planning under Order No. 1000.[3484]

1630. We believe that the local transmission planning information provided pursuant to the enhanced transparency requirements that we adopt in this final order will better facilitate the identification through the regional transmission planning process of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities.[3485] Specifically, transmission providers' local transmission planning information will be subject to review and comment by stakeholders that may provide additional information or identify considerations that could inform the criteria, models, and assumptions used in local transmission planning, the identification of local transmission needs, and the identification of transmission facilities to address those local transmission needs. Because local transmission planning information serves as an input to the regional transmission planning process, these improvements will, in turn, facilitate the identification of more efficient or cost-effective transmission facilities in the regional transmission planning process, resulting in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.

1631. With respect to the comments from National and State Conservation Organizations and WE ACT[3486] that robust input from affected and overburdened communities in the local transmission planning process is important, we believe that the added transparency requirements that require transmission providers to identify and publicly post the information and then conduct stakeholder meetings as part of the regional transmission planning process, provides an opportunity for interested parties to engage and comment on the information.

1632. With regard to commenters that suggest that the additional transparency requirements proposed in the NOPR will not be effective because they do not go far enough in making changes to local transmission planning processes,[3487] we find that the enhanced transparency requirements that we adopt in this final order are specifically designed to provide needed transparency to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. In addition, we find that other commenters' suggestions for changes to local transmission planning processes were not proposed in the NOPR and therefore are outside the scope of this proceeding. We conclude that the replacement rate set forth herein is just and reasonable and addresses the deficiencies identified herein.[3488] We note that the Commission continues to examine a suite of related issues in its Transmission Planning and Cost Management proceeding.[3489]

1633. In response to American Municipal Power's assertion that the PJM Attachment M–3 process has increased the problem of planning based on individual transmission owners' criteria and the balkanization of the transmission planning process,[3490] we find that American Municipal Power has not persuasively explained why these concerns are the result of increasing the *transparency* of local transmission planning, rather than other factors associated with the PJM Attachment M–3 process. Based on the record before us, we do not expect that requiring enhanced transparency in local transmission planning, in the manner directed in this final order, will result in greater incentives for transmission providers to develop local transmission facilities in lieu of regional transmission facilities. Instead, we expect that additional opportunities for stakeholder review of and comment on local transmission planning inputs into the regional transmission planning process will help to facilitate the identification of regional transmission facilities that are more efficient or cost-effective compared to transmission facilities identified in the local transmission planning process.

1634. We disagree with commenters that state that the NOPR proposal is not needed in their transmission planning region because their local transmission planning process is already sufficiently transparent.[3491] The reforms that we adopt here are necessary to ensure just and reasonable rates, as more fully explained above. Additionally, we believe that these reforms to enhance the transparency of local transmission planning inputs into the regional transmission planning process are necessary to ensure that interested stakeholders have an opportunity to meaningfully participate in the review of the local transmission planning assumptions, needs, and solutions before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1635. Similarly, we disagree with commenters that oppose the proposal because it may interfere with existing transmission planning processes.[3492] As we explain above, the enhanced transparency and opportunities for stakeholder participation are needed to ensure just and reasonable Commission-jurisdictional rates. Although we appreciate that there may be differences in how transmission providers currently conduct local transmission planning, we believe that the standard baseline of transparency established by the requirements adopted in this final order is needed to ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning inputs that go into the regional transmission planning process and to ensure that the regional transmission planning process can identify regional transmission facilities that address transmission needs more efficiently or

[3484] *Id.* PP 78–84.

[3485] NOPR, 179 FERC ¶ 61,028 at P 402.

[3486] National and State Conservation Organizations Initial Comments at 2; WE ACT Initial Comments at 5–6.

[3487] *See* American Municipal Power Initial Comments at 17–18; Ohio Commission Federal Advocate Initial Comments at 19–20.

[3488] *See New York* v. *FERC,* 535 U.S.at 26–28 (upholding Commission's decision not to assert jurisdiction over bundled retail transmission).

[3489] *See* Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22–8–000 (Apr. 21, 2022).

[3490] American Municipal Power Initial Comments at 17.

[3491] APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial Comments at 46–50; Dominion Initial Comments at 69–70; Eversource Initial Comments at 46–49; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16–18.

[3492] Avangrid Initial Comments at 13; CAISO Initial Comments at 7, 47; Dominion Initial Comments at 70; Eversource Initial Comments at 47–48; MISO Initial Comments at 86; PG&E Initial Comments at 17–18; PPL Initial Comments at 36; Xcel Initial Comments at 16–17.

cost-effectively than local transmission facilities. The fact that transmission providers may need to adjust their existing processes to comply with these requirements is not a sufficient reason for the Commission to decline to adopt them.

1636. We also disagree with commenters that argue that the proposal is too prescriptive.[3493] We believe that these requirements strike a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. In fact, experience with the PJM Attachment M–3 process, which includes similar requirements to those adopted in this final order, provides evidence that it is possible to satisfy these requirements with a process that allows transmission providers to produce their local transmission plans on a timely basis.[3494] In response to National Grid's concern that the NOPR proposal would impose a new requirement to integrate their local transmission planning with regional transmission planning,[3495] the final order imposes no new requirements beyond the three meetings and associated opportunities for comment described above. We believe that these requirements add only a small but manageable burden for transmission providers, which is outweighed by the transparency benefits that would accrue to stakeholders participating in the local and regional transmission planning processes.

1637. With respect to the comments of APS and National Grid that local transmission planning cycles might be delayed by the new transparency requirements,[3496] we reiterate that the final order strikes a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. We believe that, even with the additional requirements that we establish here, it is possible for transmission providers to produce local transmission plans within a 12-month period, especially given that when scheduling the three required meetings, transmission providers need not leave more than 25 calendar days between each meeting. The experience of PJM TOs, whose local transmission planning processes are subject to similar requirements, demonstrates that it is possible to satisfy these requirements in a timely manner.[3497]

a. Specific Stakeholder Meeting Requirements

1638. We address in this section the requirements specific to the implementation details associated with the three publicly-noticed stakeholder meetings that transmission providers are required to conduct: the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, that were discussed above. We believe that these requirements strike a reasonable balance between providing adequate time to allow interested stakeholders to review and comment on local transmission planning inputs that are used in regional transmission planning and allowing the efficient and timely execution of the local transmission planning process. In our view, allowing transmission providers to limit the length of time between the three required meetings accomplishes this balance.

1639. With respect to commenters who argue that a minimum of 25 calendar days between publicly-noticed stakeholder meetings is too short,[3498] we disagree. The minimum period between stakeholder meetings is just that, a minimum, and we expect that transmission providers and their stakeholders will, in practice, implement a schedule for the required stakeholder meetings that best meets the needs of their transmission planning region. However, we find that a minimum of less than 25 calendar days between stakeholder meetings would not allow stakeholders to participate in a meaningful way, and we therefore adopt this minimum period as an appropriate baseline for providing stakeholders with a meaningful opportunity to review and comment on local transmission planning inputs that are used in regional transmission planning. And, in fact, at least some transmission providers have adopted this minimum duration between stakeholder meetings.[3499]

1640. We clarify that transmission providers are required to provide information at least five calendar days prior to each of the three publicly-noticed stakeholder meetings. As stated above, transmission providers must publicly notice each meeting and publicly post all materials for stakeholder review during the three meetings and provide opportunities for stakeholders to submit comments before and after each meeting. We believe that providing this information at least five calendar days prior to each of the three stakeholder meetings strikes a balance between giving stakeholders meaningful opportunity to review the meeting materials ahead of each meeting and limiting the burden to transmission providers in posting the materials ahead of time. Furthermore, the information that we require transmission providers to share is information that they use in their local transmission planning processes and, thus, is information that they generally already possess.

1641. We disagree with commenters that argue that three separate publicly-noticed stakeholder meetings are unnecessary and will increase workload without any benefit, or that a single meeting would address the Commission's transparency concerns more efficiently, or request that the Commission not dictate the number of stakeholder meetings.[3500] We note that Indicated PJM TOs state that the PJM Attachment M–3 process has the benefit of avoiding duplication of projects between local and regional transmission planning processes.[3501] We also disagree with MISO's argument that we should allow each transmission planning region to have complete discretion over the timing of the meetings, as well as the specific information to be covered at the meetings.[3502] While we allow flexibility in certain aspects of the transmission planning processes, we find that the requirement to hold three separate

[3493] *See* Avangrid Initial Comments at 13–15; EEI Initial Comments at 40; Eversource Initial Comments at 47–48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39–41; New York TOs Initial Comments at 7, 16–17; Xcel Initial Comments at 17.

[3494] *See* Indicated PJM TOs Initial Comments at 42–43 (citations omitted).

[3495] National Grid Initial Comments at 39–40.

[3496] APS Initial Comments at 13; National Grid Initial Comments at 39–40.

[3497] Exelon Initial Comments at 3–4, 51–52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)); Indicated PJM TOs Initial Comments at 42–43.

[3498] American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; TAPS Initial Comments at 6, 62.

[3499] See PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0.), which, briefly, refers to the additional transparency and stakeholder input rules around transmission facilities that are not eligible for selection, but, though classified as local transmission facilities, nonetheless impact the identification and selection of regional transmission facilities. *See also Duke Energy Carolinas, LLC,* 186 FERC ¶ 61,178, at PP 13, 27 (2024) (accepting Duke's OATT revisions to adopt a stakeholder meeting process that includes an Assumptions Meeting, Needs Meeting, and Solutions Meeting, each no fewer than 25 calendar days apart).

[3500] Dominion Initial Comments at 68; Eversource Initial Comments at 47–48; NESCOE Initial Comments at 78; Xcel Initial Comments at 17.

[3501] Indicated PJM TOs Initial Comments at 42.

[3502] MISO Initial Comments at 84.

stakeholder meetings a minimum of 25 calendar days apart and prescribing the type of information that transmission providers must share at each meeting is necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. We balance the increased burden imposed on transmission providers with the benefits associated with providing increased information and opportunities for stakeholder review of and comment on the local transmission planning inputs that are used in the regional transmission planning process. In addition, as discussed above, we believe that these reforms will reduce after-the-fact disputes and will help facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities. As a result, the incremental burden of having to hold three stakeholder meetings to share this information and to consider input from stakeholders in response to this information is outweighed by the benefits that the increased transparency will provide.

1642. We also find unconvincing Eversource's assertion that the reforms will not work where there is not a precisely defined regional transmission planning cycle, such as is the case in ISO–NE.[3503] The requirement to hold three publicly-noticed stakeholder meetings is triggered by the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process and is not tied to a particular transmission planning cycle. Nevertheless, we recognize that these reforms may require transmission providers to propose adjustments to their existing processes. But as explained above, we believe that the need for transparency and stakeholder involvement requires these changes to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

1643. In response to TAPS' request that transmission providers be required to post their transmission planning criteria, models, and assumptions,[3504] we reiterate that transmission providers must provide this information as part of the Assumptions Meeting. We further note that the requirement for transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission systems is an existing requirement of Order No. 890. This information must enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.[3505] The Commission recognized in Order No. 890 that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities and, therefore, requires that transmission providers have mechanisms in place in their OATTs to manage confidentiality and CEII concerns, such as confidentiality agreements and password-protected access to information.[3506] However, we reiterate that information must be disclosed, under applicable confidentiality provisions, if the information is needed to participate in the transmission planning process and to replicate transmission planning studies, which necessarily includes access to the models that underlie transmission planning processes.

1644. We decline to require, as requested by American Municipal Power and TAPS, that transmission providers hold two Solutions Meetings.[3507] While a transmission provider may determine that additional stakeholder meetings are appropriate or necessary, we only require transmission providers to conduct the three publicly-noticed stakeholder meetings discussed above. However, there is nothing in this final order that prohibits transmission providers from holding additional meetings, beyond those required here. We find NRG's request that the Commission require the local transmission planning process include an estimated rate impact for each year if the local transmission plan were to be executed to be beyond the scope of the proposal, although transmission providers may choose to provide this information outside of the context of this order.

1645. In response to commenters that request that the Commission require transmission providers to respond to all comments and questions submitted by stakeholders in the local transmission planning process,[3508] we clarify that such a requirement could be too prescriptive in certain circumstances and thus we decline to set a bright-line rule that transmission providers must respond to each and every question or comment received through the stakeholder process. Nevertheless, we require transmission providers to respond to questions or comments in a manner that allows stakeholders to meaningfully participate in these stakeholder meetings. For example, in the context of live discussions in any of the three required publicly-noticed stakeholder meetings, we expect transmission providers to offer stakeholders an opportunity to speak, engage, and ask questions, as well as receive reasonable responses at the meeting consistent with meaningful participation. Overall, we encourage transmission providers to be as responsive as possible to stakeholder comments and questions. However, we recognize that not all comments or questions require an answer or a response, or that some responses may be unduly burdensome to the transmission provider. To the extent that there are disagreements, we note that stakeholders have dispute resolution procedures available, as required under Order No. 890.[3509] Some commenters have asked the Commission to require transmission providers to provide ''additional clarity'' regarding how alternatives were developed and why they were not selected during the Solutions Meeting, as requested by American Municipal Power.[3510] In balancing the need for transparency and the burden for transmission providers, we find that a meaningful participation standard regarding sharing of local transmission planning inputs that are used in the regional transmission planning process that are established by the Commission is reasonable.

1646. In addition, in response to TAPS' request regarding disputes over local transmission planning inputs,[3511] we clarify that where disputes arise regarding transparency into the local transmission planning inputs, the transmission provider's existing dispute resolution process, as established in Order No. 890, governing the transmission planning process should be used.[3512] Further, affected entities

[3503] Eversource Initial Comments at 47.

[3504] TAPS Initial Comments at 61.

[3505] Order No. 890, 118 FERC ¶ 61,119 at P 471.

[3506] *Id.* P 460.

[3507] American Municipal Power Initial Comments at 24–25; TAPS Initial Comments at 62 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

[3508] *See* American Municipal Power Initial Comments at 18–19; California Commission Initial Comments at 112–113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky Commission Chair Chandler Initial Comments at 21–22; Northwest and Intermountain Initial Comments at 20–21; TAPS Initial Comments at 62.

[3509] Order No. 890, 118 FERC ¶ 61,119 at PP 501–503.

[3510] American Municipal Power Initial Comments at 24–25.

[3511] TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501–503).

[3512] Order No. 890, 118 FERC ¶ 61,119 at P 501.

retain any rights that they may have under FPA section 206 to file complaints with the Commission.

b. Additional Issues

1647. As it pertains to PPL's request that the Commission clarify that confidential or sensitive information will be protected,[3513] we clarify that transmission providers must continue to apply the same safeguards to protect sensitive or critical information, such as confidentiality agreements and password protected access to information, as the Commission required in Order No. 890 and that transmission providers currently apply to the sharing of transmission planning information to protect against inappropriate disclosure of confidential information.[3514]

1648. Many commenters suggest additional reforms because these commenters find the NOPR proposal insufficient. These suggested reforms include additional measures to protect customers' interests and additional process, more oversight, more monitoring (including establishing an independent transmission monitor), or prudence reviews;[3515] requiring RTOs/ISOs to assume a larger role in reviewing or approving identified local transmission projects;[3516] requiring a performance-based method of enhancing transparency in local transmission planning processes;[3517] and requiring transmission providers to make available additional transmission planning data,[3518] improve formatting of transmission planning inputs,[3519] or otherwise coordinate with load-serving entities to transfer data and information.[3520] The Commission did not make such proposals in the NOPR and, as a result, we find these requests to be beyond the scope of this proceeding and decline to adopt them. We note, however, that several of these issues may be examined in the Commission's ongoing Transmission Planning and Cost Management proceeding.[3521]

C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

1. Eligibility

a. NOPR Proposal

1649. The Commission proposed to require, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. The Commission proposed to define "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[3522]

1650. The Commission described the process under this proposed reform as entailing the following steps. First, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider would submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if a right-sized replacement transmission facility is identified as a potential solution to a Long-Term Regional Transmission Planning need, that right-sized replacement transmission facility would be evaluated in the same manner as any other proposed transmission facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets all of the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution to a transmission need identified through Long-Term Regional Transmission Planning, then the right-sized replacement transmission facility may be selected in the regional transmission plan for purposes of cost allocation.[3523]

1651. The Commission explained that nothing in the reforms proposed in the NOPR would alter a transmission provider's existing rights and responsibilities under existing laws with respect to maintaining, and when necessary, replacing, existing transmission facilities. Further, as the Commission explained, it may be possible for an in-kind replacement transmission facility to be *included* in the regional transmission plan for informational purposes, but not be *selected*.[3524]

b. Comments

1652. Several commenters support the NOPR's proposals related to right-sizing.[3525] ITC states that the NOPR proposal will result in better use of existing facilities and rights-of-way to quickly deliver additional transmission capacity. ITC maintains that increasing the transfer capability of existing transmission facilities lessens the impacts on communities and other land users, in addition to raising fewer environmental considerations.[3526] ITC adds that right-sizing will form a critical input to transmission planning and state siting processes by encouraging designs that meet future needs.[3527]

1653. OMS also supports the Commission's proposed realignment of incentives to ensure that transmission providers are not incentivized through right-sizing to rebuild and replace facilities before considering other opportunities, instead providing a level playing field to consider other solutions.[3528] PJM states that right-sizing allows transmission owners to meet their reliability obligations while transmission providers have the opportunity to find more efficient

[3513] PPL Initial Comments at 36.

[3514] Order No. 890, 118 FERC ¶ 61,119 at PP 460, 471.

[3515] California Commission Initial Comments at 111–112 &n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25–29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23–24; OMS Initial Comments at 16–17; Pattern Energy Initial Comments at 31–34; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 51–52; PJM States Initial Comments at 4–6; TAPS Initial Comments at 61–62; US DOJ and FTC Initial Comments at 20–21.

[3516] *See* American Municipal Power Reply Comments at 3–7; California Commission Initial Comments at 108–110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60–61; Ohio Consumers Reply Comments at 17–18; PJM States Initial Comments at 6–7.

[3517] Vermont Electric and Vermont Transco Initial Comments at 5.

[3518] American Municipal Power Initial Comments at 21–24 (citations omitted); Pattern Energy Initial Comments at 30–34.

[3519] Joint Consumer Advocates Initial Comments at 21–22.

[3520] Certain TDUs Initial Comments at 18.

[3521] Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22–8–000 (Apr. 21, 2022).

[3522] NOPR, 179 FERC ¶ 61,028 at P 403.

[3523] *Id.* P 407.

[3524] *Id.* PP 412–413.

[3525] ACORE Initial Comments at 19; Ameren Initial Comments at 46–47; APPA Initial Comments at 48; California Energy Commission Initial Comments at 3; CTC Global Initial Comments at 18; ELCON Initial Comments at 27; Evergreen Action Initial Comments at 4; ITC Initial Comments at 45; ITC Reply Comments at 29; New York Commission and NYSERDA Initial Comments at 15; Northwest and Intermountain Initial Comments at 21; OMS Initial Comments at 17; PJM Initial Comments at 9, 121–122; SEIA Initial Comments at 26; U.S. Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

[3526] ITC Initial Comments at 45.

[3527] ITC Reply Comments at 29.

[3528] OMS Initial Comments at 17.

solutions to regional transmission needs and avoid duplicative transmission development.[3529]

1654. AEP supports applying the right-sizing evaluation to transmission facilities operating at or above 230 kV because replacement transmission facilities that will operate at or above 230 kV are most susceptible to modification to meet long-term regional transmission needs.[3530] PG&E also supports the proposed voltage threshold, claiming that the inclusion of lower voltage transmission projects would substantially expand the number of projects that would need to be evaluated for right-sizing while offering little benefit. Specifically, PG&E contends that lower voltage transmission projects are typically needed for specific, local purposes and thus do not need to be right-sized, and that a requirement that they be evaluated for right-sizing would burden the RTO/ISO process.[3531]

1655. APPA supports the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.[3532] AEP also supports a 10-year horizon for identifying in-kind replacements, so long as the list of transmission facilities is non-binding and may be modified as transmission projects mature or expected facility lives can be extended through other means.[3533]

1656. CAISO requests that the Commission clarify that the NOPR does not preclude it from continuing to consider modifications to in-kind replacements for transmission facilities below 230 kV in its annual transmission planning process.[3534]

1657. Several commenters support the NOPR's right-sizing proposal but with certain conditions.[3535] Further, some commenters argue that if the Commission adopts the NOPR proposal, the Commission must ensure that the proposal does not disrupt or impair existing local transmission planning processes.[3536] For example, AEP asserts that the Commission must ensure that the NOPR proposal does not undermine the local transmission planning process or transmission owners' rights to build transmission projects that address local needs.[3537] Mississippi Commission asserts that, if the NOPR proposal is adopted, the ultimate decision as to which local transmission project is constructed must rest with the states that have transmission siting authority and the incumbent transmission owners.[3538] PJM States ask for clarification on how the NOPR proposal will interact with existing processes, noting that in PJM, any need that appears both on a five-year end-of-life needs list and in PJM's regional transmission plan is eligible for competition (as compared to the NOPR proposal, under which transmission projects to address 10-year-out needs would not be eligible for competition).[3539]

1658. NESCOE states that ISO–NE lacks the clear standards required to support right-sizing, citing an Eversource transmission project that improved grid reliability but was ineligible for regional cost allocation because it did not meet the standards to qualify as a right-sized project.[3540] NESCOE argues that more transparency into the right-sizing processes is necessary to ensure that the results are disciplined, cost-conscious investments.[3541]

1659. Several commenters oppose the NOPR's right-sizing proposal.[3542] Competition Coalition asserts that the NOPR proposal would result in over-building the transmission system now for speculative future transmission needs, leaving customers with the bill for any stranded costs.[3543] Louisiana Commission claims that the NOPR right-sizing proposal should not be adopted because it will intrude on its retail authority.[3544]

1660. Other commenters argue that the proposed 230 kV threshold is inappropriate.[3545] For example, Avangrid contends that it is overly prescriptive and does not reflect regional conditions, needs, and stakeholder interests.[3546] Avangrid states that, in ISO–NE, a 230 kV threshold would result in in-kind replacement of lower voltage transmission facilities rather than right-sizing facilities to most efficiently meet transmission needs identified through Long-Term Regional Transmission Planning.

1661. Kentucky Commission Chair Chandler argues that 200 kV or 230 kV are no longer adequate rules of thumb to delineate local versus regional transmission facilities, as transmission facilities that may have been formerly classified as local are likely to be regional in the future. Rather, Kentucky Commission Chair Chandler states that transmission facilities rated between 100 kV and 200 kV will play a greater role in the regional delivery of energy.[3547] Ohio Consumers argue that the Commission should lower the threshold to 69 kV because many end-of-life transmission facilities in the PJM transmission planning process are expensive rebuilds of transmission facilities that are rated below 230 kV.[3548] TAPS argues that excluding lower voltage facilities prevents transmission planning regions from being able to consider more efficient and cost-effective alternatives.[3549]

1662. LS Power asserts that the Commission should not limit its right-sizing proposal to facilities above 230 kV and that such reforms should apply

[3529] PJM Initial Comments at 121–122 (citing NOPR, 179 FERC ¶ 61,028 at PP 406, 408).

[3530] AEP Initial Comments at 44–45 (citing NOPR, 179 FERC ¶ 61,028 at P 406).

[3531] PG&E Reply Comments at 14–15.

[3532] APPA Initial Comments at 48 (citing NOPR, 179 FERC ¶ 61,028 at P 403).

[3533] AEP Initial Comments at 44–45.

[3534] CAISO Initial Comments at 50.

[3535] ACEG Initial Comments at 8–9, 56–58; AEP Initial Comments at 43–44; Avangrid Initial Comments at 15–16; Breakthrough Energy Initial Comments at 3, 19; California Commission Initial Comments at 113–118; California Water Initial Comments at 8–9; Clean Energy Associations Initial Comments at 36–37; EEI Initial Comments at 41; Eversource Initial Comments at 52; Exelon Initial Comments at 3, 51; ISO–NE Initial Comments at 39; MISO Initial Comments at 87; NARUC Initial Comments at 58–59, 63–64; NESCOE Initial Comments at 21–22, 78–79; NESCOE Reply Comments at 6–8; NESCOE Supplemental Comments at 7–9; NextEra Initial Comments at 66–67; NRECA Initial Comments at 67; NYISO Initial Comments at 58–60; PG&E Initial Comments at 12–14; Pine Gate Initial Comments at 46–50; PIOs Initial Comments at 57–58; State Agencies Initial Comments at 20–22; TAPS Initial Comments at 6–7, 64; VEIR Initial Comments at 6; Vermont State Entities Initial Comments at 11–13; WIRES Initial Comments at 10.

[3536] *See* AEP Initial Comments at 43–44; CAISO Initial Comments at 50; Mississippi Commission Initial Comments at 30–31; Mississippi Commission Reply Comments at 9–10; PJM States Initial Comments at 8; WIRES Initial Comments at 10.

[3537] AEP Initial Comments at 43–44.

[3538] Mississippi Commission Initial Comments at 30–31.

[3539] PJM States Initial Comments at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0), section (d)1.iii).

[3540] NESCOE Reply Comments at 6–8.

[3541] NESCO Supplemental Comments at 9.

[3542] Anbaric Initial Comments at 7; Competition Coalition Initial Comments at 62–63; DC and MD Offices of People's Counsel Initial Comments at 47–48; Idaho Power Initial Comments at 13; Kentucky Commission Chair Chandler Initial Comments at 16–19; Louisiana Commission Initial Comments at 39; LS Power Initial Comments at 135–136, 138, 141–142, 145–146; Massachusetts Attorney General Initial Comments at 51–52; Ohio Consumers Initial Comments at 23; Resale Iowa Initial Comments at 8–9.

[3543] Competition Coalition Initial Comments at 62–63.

[3544] Louisiana Commission Initial Comments at 39.

[3545] Avangrid Initial Comments at 15–16; California Commission Initial Comments at 117–118; Kentucky Commission Chair Chandler Initial Comments at 18–19; New York TOs Initial Comments at 17–18; NYISO Initial Comments at 59; Ohio Consumers Initial Comments at 23; PJM Initial Comments at 9, 121–122; State Agencies Initial Comments at 20–21; TAPS Initial Comments at 6, 66.

[3546] Avangrid Initial Comments at 15–16.

[3547] Kentucky Commission Chair Chandler Initial Comments at 18–19.

[3548] Ohio Consumers Initial Comments at 23.

[3549] TAPS Initial Comments at 6, 66.

to lower voltage transmission facilities as well.[3550] Specifically, LS Power argues that transmission facilities that operate at or above 100 kV (and sometimes facilities operating at a lower voltage) are regional in nature and should be subject to exclusively regional transmission planning.[3551]

1663. Shell states that the Commission should consider lowering the proposed voltage threshold to 115 kV, but notes that doing so may include lower voltage facilities that predominantly serve sub-transmission, wholesale distribution, or retail distribution purposes and have only local benefits.[3552] To ensure that the costs of sub-transmission, wholesale distribution, or retail distribution facilities are not rolled into transmission rates, Shell argues that the Commission should reexamine its standards for rolling the costs of transmission facilities into rates, its application of the Seven Factor test for functionalizing facilities as distribution or transmission, and its *Mansfield* integration analysis.[3553] Western Utilities contend that the Commission should not adopt Shell's proposal to lower the right-sizing threshold to 115 kV because whether or not a facility is a transmission facility is a fact-specific question.[3554]

1664. Pine Gate recommends against the Commission adopting the bright-line voltage threshold specified in the NOPR, but urges the Commission require each transmission provider to: (1) list and evaluate existing transmission facilities operating at or above 230 kV that it owns and estimates may need to be replaced with a new in-kind transmission facility over the next 10 years; and (2) establish criteria by which it will identify lower-voltage facilities that could potentially be right-sized through Long-Term Regional Transmission Planning.[3555] Relatedly, WIRES states that the Commission should either: (1) clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities at a lower voltage threshold if existing transmission planning processes already do so; or (2) provide flexibility for transmission planning regions to justify the use of a different voltage threshold.[3556]

1665. Some commenters oppose the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.[3557] Exelon states that the Commission's proposed requirement to have a 10-year time horizon for identifying a list of potential end-of-useful life needs is infeasible and inconsistent with utility practices. Specifically, Exelon states that it does not develop a concrete plan for transmission projects to meet end-of-useful life needs five years in advance—let alone 10 years—but instead maintains a ''dynamic list'' of older assets, the condition of which is evaluated on a rolling basis, based on numerous factors such as equipment inspection and testing, maintenance history, historical performance, obsolescence, operational experience, asset criticality, equipment failure data, and age.[3558]

1666. Some commenters argue that the NOPR proposal is not applicable to their transmission planning regions or that their existing processes are sufficient.[3559] For example, CAISO explains that it plans all upgrades and expansions of transmission facilities under its operational control, which include transmission facilities at all voltage levels and at all locations on the system. Further, CAISO states that, if an asset management, maintenance, or in-kind replacement project can be expanded or modified to address a CAISO-identified transmission need in a local area (or system wide), CAISO can order such expansion or modification in its regional transmission planning process.[3560]

1667. MISO asserts that right-sizing is fundamental to transmission planning and should always be considered as part of Good Utility Practice, but that right-sizing decisions are best made on a case-by-case basis, as there are both quantitative and qualitative considerations that must be taken into account.[3561] MISO contends that its existing local transmission planning achieves the Commission's objectives, as the MISO process provides for right-sizing where MISO selects the most robust solution. Accordingly, MISO states that, for its footprint, no changes are needed.[3562]

1668. SERTP Sponsors argue that replacement decisions for particular equipment may be triggered more by the conditions of a particular facility than its age. SERTP Sponsors argue that a process like right-sizing already occurs in SERTP's regional transmission planning, which requires that the SERTP Sponsors affirmatively look to determine if there are regional transmission alternatives that would be more efficient or cost-effective than the transmission solutions otherwise included in SERTP's regional transmission plan, including projects to replace aging infrastructure.[3563]

1669. Several commenters argue that the Commission should adopt alternative or additional requirements that apply when transmission providers evaluate transmission facilities for right-sizing.[3564] For example, Ameren requests that the Commission require transmission providers to consider the following additional criteria when determining whether a transmission facility is eligible for right-sizing: (1) whether a transmission line is in the top 10 limiting elements on an import or transfer study; (2) whether a line has shown up as a real-time binding

[3550] *See* LS Power Partial Reply Comments at 61–64 (citing California Commission Initial Comments at 117; Eversource Initial Comments at 38; ISO–NE Initial Comments at 39; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 142; NARUC Initial Comments at 64; Ohio Consumers Initial Comments at 23; State Agencies Initial Comments at 21).

[3551] *Id.* at 64.

[3552] Shell Reply Comments at 10 (citing Shell Initial Comments at 34).

[3553] Shell Initial Comments at 34–36; Shell Reply Comments at 10–11 (citing *Commonwealth Edison Co.,* 167 FERC ¶ 61,173, at P 12 n.23 (2019); *Buckeye Power, Inc.* v. *Am. Transmission Sys. Inc.,* Opinion No. 533, 148 FERC ¶ 61,174, at PP 12, 41, 69 (2014), *order on reh'g,* 151 FERC ¶ 61,091 (2015); *Mansfield Mun. Elec. Dep't* v. *New England Power Co.,* Opinion No. 454, 97 FERC ¶ 61,134 (2001), *order on reh'g,* Opinion No. 454–A, 98 FERC ¶ 61,115 (2002)).

[3554] *See* Western Utilities Reply Comments at 2 (citing Shell Initial Comments at 34–35).

[3555] Pine Gate Initial Comments at 48.

[3556] WIRES Initial Comments at 10.

[3557] Eversource Initial Comments at 53; Exelon Initial Comments at 54–55; Indicated PJM TOs Initial Comments at 46–47; Kentucky Commission Chair Chandler Initial Comments at 17–18; SERTP Sponsors Initial Comments at 38–39.

[3558] Exelon Initial Comments at 54–55 (*Exelon Utilities Asset Management Guidelines and Practices* 3 (Nov. 18, 2020), *https://pjm.com/-/media/committees-groups/committees/srrtep-ma/2020/20201216/20201216-exelon-final-end-eol-guidelines.ashx*).

[3559] CAISO Initial Comments at 47–48; Dominion Initial Comments at 69–70, 72; Duke Initial Comments at 46; MISO Initial Comments at 87–88; MISO Reply Comments at 28; New York TOs Initial Comments at 17; SERTP Sponsors Initial Comments at 38–39; SPP Initial Comments at 34–35.

[3560] CAISO Initial Comments at 47–48 (citing CAISO ANOPR Initial Comments at 73; *Cal. Pub. Utils. Comm'n* v. *Pac. Gas and Elec. Co.,* 164 FERC ¶ 61,161 at PP 35–37, 69).

[3561] MISO Initial Comments at 87.

[3562] MISO Reply Comments at 28 (citing OMS Initial Comments at 15–17).

[3563] SERTP Sponsors Initial Comments at 38–39 (citations omitted).

[3564] ACEG Initial Comments at 58; Ameren Initial Comments at 46–47; American Municipal Power Initial Comments at 27; Breakthrough Energy Initial Comments at 18–19; California Energy Commission Initial Comments at 3; Competition Coalition Initial Comments at 68; CTC Global Initial Comments at 18; Eversource Initial Comments at 53; Exelon Initial Comments at 56–58; Grid United Initial Comments at 3–4; Pennsylvania Commission Initial Comments at 21; PG&E Initial Comments at 13–14; Pine Gate Initial Comments at 48; PIOs Initial Comments at 57–58; PJM Initial Comments at 9, 121–122; PPL Initial Comments at 36–37; Shell Initial Comments at 34.

constraint in the last two years; or (3) whether a line shows up as a binding constraint in future security constrained economic dispatch simulations.[3565] California Energy Commission argues that the Commission should develop a definition of ''right-sizing,'' possibly tied to a specified planning reserve margin as well as an expected level of demand growth.[3566] Furthermore, ACEG and PG&E both request that the Commission consider the use of existing transmission facility rights-of-way as an eligibility threshold for potentially right-sized replacement transmission facilities.[3567]

1670. Eversource asserts that it would be more efficient to evaluate potential right-sizing: (1) through a review of the transmission facilities that could be upgraded to address identified long-term transmission needs, including an evaluation of whether an in-kind replacement is likely to occur during the planning horizon; or (2) through transmission owner identification of right-sizing options that align with needs identified in the longer-term study as they perform their normal asset condition projects.[3568]

1671. Entergy asserts that the Commission should clarify that storm-hardening transmission projects are not subject to a right-sizing requirement because it would add complications and delays to the right-sizing process.[3569] Pennsylvania Commission argues that a transmission facility should not be right-sized if its total cost exceeds the total cost of the local transmission project and a competitively procured transmission project to address the regional need.[3570]

1672. Some commenters call for the Commission to expand the right-sizing reform to other categories of transmission facilities.[3571] Eversource argues that the Commission should encourage transmission providers to incorporate right-sizing considerations into other transmission planning processes, such as the reliability planning process, as appropriate.[3572] Similarly, ACORE and American Municipal Power request that the Commission clarify that right-sizing also applies in any short-term transmission planning for reliability and economic transmission projects.[3573] Grid United states that the Commission should require Long-Term Regional Transmission Planning to assess and allow for up-sizing transmission projects, such as building a single circuit transmission line that is double-circuit ready.[3574]

1673. Several commenters argue that the Commission should allow flexibility on the thresholds for evaluating transmission facilities for right-sizing.[3575] To prevent needless litigation that will cause delays and cost increases for customers, Dominion states that any final order should be clear that transmission providers will not be penalized if a replacement project arises that was not previously identified.[3576]

1674. NYISO contends that the final order should permit transmission providers, with input from state entities and stakeholders, to integrate planning for right-sizing transmission replacements into existing transmission planning processes, including by considering transmission facilities that they anticipate will be replaced in-kind when identifying transmission needs in short-term or long-term transmission planning.[3577]

1675. US DOE encourages the Commission to provide sufficient flexibility to ensure that the proposed reforms are cost-effective and do not overburden the transmission planning process. US DOE asserts that transmission providers should not be required to submit every in-kind replacement for all equipment above 230 kV for consideration for right-sizing and that regional transmission planning processes should not be required to consider each piece of equipment provided by each member of a transmission planning region.[3578]

1676. PG&E argues that the Commission should allow for flexibility in any right-sizing-related requirements, noting that a transmission provider may need to replace an aging or failing transmission facility sooner than a right-sized transmission project can be developed. In that case, PG&E states that the transmission owner would need to proceed with the replacement project to ensure reliability or protect public safety even if the RTO/ISO had determined that a transmission facility would benefit from being right-sized.[3579]

c. Commission Determination

1677. We adopt the NOPR proposal, with modification, to require that, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region evaluate whether transmission facilities (1) operating above a specified kV threshold and (2) that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be ''right-sized'' to more efficiently or cost-effectively address a Long-Term Transmission Need. To effectuate this reform, we also adopt the NOPR proposal, with modification, to require that, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider submit its in-kind replacement estimates (*i.e.,* estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) for use in Long-Term Regional Transmission Planning. With respect to the specified kV threshold, transmission providers must propose on compliance a threshold that does not exceed 200 kV (*e.g.,* 115 kV and above). In adopting the right-sizing reform in this final order, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. We also adopt the NOPR proposals regarding a Federal right of first refusal and cost allocation method for right-sized replacement transmission facilities, as discussed below.

[3565] Ameren Initial Comments at 46–47.

[3566] California Energy Commission Initial Comments at 3.

[3567] ACEG Initial Comments at 57–58; PG&E Initial Comments at 13.

[3568] Eversource Initial Comments at 53.

[3569] Entergy Initial Comments at 38.

[3570] Pennsylvania Commission Initial Comments at 21.

[3571] American Municipal Power Initial Comments at 27; Avangrid Initial Comments at 16; Clean Energy Associations Initial Comments at 26–27, 37; Eversource Initial Comments at 54; MISO Initial Comments at 88; NYISO Initial Comments at 59–60; PIOs Initial Comments at 57–58; TAPS Initial Comments at 6, 64–65.

[3572] Eversource Initial Comments at 54.

[3573] ACORE Initial Comments at 19; American Municipal Power Initial Comments at 27.

[3574] Grid United Initial Comments at 4.

[3575] American Municipal Power Initial Comments at 27; APPA Initial Comments at 48; Avangrid Initial Comments at 15–16; California Commission Initial Comments at 117; Clean Energy Associations Initial Comments at 36–37; Dominion Initial Comments at 72–73; EEI Initial Comments at 41; Eversource Initial Comments at 52–53; ISO–NE Initial Comments at 39; NARUC Initial Comments at 58–59, 63–64; National Grid Initial Comments at 40–41; NESCOE Initial Comments at 80; New York TOs Initial Comments at 18; NRECA Initial Comments at 67; NYISO Initial Comments at 9, 60; PG&E Reply Comments at 14–15; PPL Initial Comments at 37; US DOE Initial Comments at 48; Vermont State Entities Initial Comments at 13; WIRES Initial Comments at 10.

[3576] Dominion Initial Comments at 73.

[3577] NYISO Initial Comments at 9, 60.

[3578] US DOE Initial Comments at 48.

[3579] PG&E Reply Comments at 15.

1678. We adopt the NOPR proposal to define ''right-sizing'' as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[3580] Additionally, we clarify that, for purposes of this right-sizing reform, an ''in-kind replacement transmission facility'' is a new transmission facility that: (1) would replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as needing to be replaced; (2) would result in no more than an incidental increase in capacity over the existing transmission facility identified as needing to be replaced;[3581] and (3) is located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility identified as needing to be replaced.

1679. Further, we clarify that a ''right-sized replacement transmission facility'' is a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate. We believe these clarifications are necessary to ensure that use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.

1680. As an example, assume that transmission providers determine that an existing transmission facility included in a transmission provider's in-kind replacement estimate can be right-sized (Segment 1) and, together with a separate new transmission facility (Segment 2), is the more efficient or cost-effective solution to a Long-Term Transmission Need. In this example, Segment 1 is a new 50-mile, 345 kV transmission facility between interconnection points A and B that requires the expansion of an existing right-of-way, and replaces an existing 50-mile, 230 kV transmission facility between interconnection points A and B. Segment 2 in this example is a new 25-mile, 345 kV transmission facility requiring entirely new rights-of-way from interconnection points B to C. If both Segment 1 and Segment 2 are selected to address a Long-Term Transmission Need, then, for purposes of the requirements of this final order, only Segment 1 would be considered a right-sized replacement transmission facility.

1681. Consistent with the NOPR proposal, and as discussed further below, the process under this proposed right-sizing reform entails taking the following steps, which transmission providers must describe in their OATTs. The transmission providers in each transmission planning region must propose a point sufficiently early in each Long-Term Regional Transmission Planning cycle at which each individual transmission provider in the transmission planning region will submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if transmission providers identify a right-sized replacement transmission facility as a potential solution to a Long-Term Transmission Need as part of Long-Term Regional Transmission Planning, that right-sized replacement transmission facility must be evaluated in the same manner as any other proposed Long-Term Regional Transmission Facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. More specifically, it is at this stage of the right-sizing reform where transmission providers must use the in-kind replacement estimates to determine if in-kind replacement transmission facilities could be right-sized to more efficiently or cost-effectively address a Long-Term Transmission Need(s). If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution to a Long-Term Transmission Need, then the right-sized replacement transmission facility must be considered for selection.

1682. We find that a right-sized replacement transmission facility has the potential to both meet an individual transmission provider's responsibility to maintain the reliability of its existing transmission system and address a Long-Term Transmission Need more efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility.[3582] Further, we find that, if opportunities for right-sized replacement transmission facilities are not considered, the Long-Term Regional Transmission Planning process may not select the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs, potentially rendering Commission-jurisdictional rates unjust and unreasonable.[3583]

1683. As noted above, for purposes of implementing the right-sizing requirements that we adopt in this final order, transmission providers must propose on compliance a threshold that does not exceed 200 kV that is used in identifying the transmission facilities that an individual transmission provider anticipates replacing in-kind with a new transmission facility during the next 10 years, which it must then include in its in-kind replacement estimates. In other words, each transmission provider in the transmission planning region must include in its in-kind replacement estimates the transmission facilities operating at and above 200 kV, or at and above a lower proposed threshold, that it owns and anticipates replacing in-kind with a new transmission facility during the next 10 years.[3584] We find that this threshold strikes a reasonable balance between capturing the transmission facilities that are the most likely candidates for right-sizing without overburdening transmission providers by requiring them to identify all transmission facilities planned for in-kind replacement, including lower voltage transmission facilities that may be less likely to provide regional benefits, and therefore potentially less likely to be more efficient or cost-effective transmission solutions to Long-

[3580] NOPR, 179 FERC ¶ 61,028 at P 403 (''Right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (*e.g.,* redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies).'').

[3581] The Commission has addressed the meaning of an incidental increase in the context of a replacement transmission facility in several orders. *See, e.g., S. Cal. Edison Co.,* 164 FERC ¶ 61,160 at P 33, *order on reh'g,* 168 FERC ¶ 61,170 (2019); *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at P 68; *see also PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136 at P 84, *order on reh'g,* 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.,* 173 FERC ¶ 61,242 at P 54, *order on reh'g,* 176 FERC ¶ 61,053 (2021).

[3582] NOPR, 179 FERC ¶ 61,028 at P 406.

[3583] *Id.*

[3584] We note that while transmission providers may not propose a kV threshold that exceeds 200 kV, they may propose a lower kV threshold (*e.g.,* 100 kV or 115 kV), which would require transmission providers in that transmission planning region to include in their in-kind replacement estimates a wider range of transmission facilities that they own and anticipate replacing in-kind with a new transmission facility during the next 10 years.

Term Transmission Needs. Specifically, we believe adopting the 230 kV threshold proposed in the NOPR could have excluded from consideration some transmission facilities planned for in-kind replacement that are likely to provide regional benefits.[3585] In adopting a specified kV threshold (so long as that threshold does not exceed 200 kV), as opposed to the 230 kV threshold proposed in the NOPR, we note that the Commission ''has wide discretion to determine where to draw administrative lines.'' [3586]

1684. We find that the requirement for transmission providers to identify a kV threshold not to exceed 200 kV to identify in-kind replacements recognizes that the NOPR proposal did not align with the region-specific characteristics outlined by some transmission providers. For example, as ISO–NE notes, a large portion of ISO–NE's transmission system consists of 115 kV transmission facilities.[3587] We find that the maximum kV threshold that we adopt allows flexibility for transmission providers, like ISO–NE, to tailor their proposed kV threshold to their specific transmission planning regions (as long as the threshold they apply is equal or lower than 200 kV), while ensuring that the in-kind replacement transmission facilities that are most susceptible to modification that could more efficiently or cost-effectively address Long-Term Transmission Needs are considered for right-sizing.

1685. With regard to the 10-year timeframe for in-kind replacement estimates, we believe that 10 years is an appropriate timeframe to evaluate potential in-kind replacement transmission facilities for right-sizing because it balances the long lead times associated with developing certain transmission facilities with the uncertainty associated with the exact timing of when aging transmission facilities may need to be replaced.[3588] We also clarify that the 10-year timeframe for in-kind replacement estimates should reflect a transmission provider's estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle. Furthermore, we believe that a 10-year timeframe is more likely to capture a larger pool of potential in-kind replacement transmission facilities that would be eligible for right-sizing. We recognize, however, that transmission providers may obtain better information about a transmission facility's condition as the anticipated replacement date approaches and may also identify additional transmission facilities that require replacement in fewer than 10 years based on updated assessments of their condition. As such, we clarify that transmission providers may update the lists of transmission facilities that they anticipate replacing in subsequent transmission planning cycles if they believe that an anticipated in-kind replacement transmission facility is more urgently needed than previously thought or if existing transmission facilities do not deteriorate as quickly as previously expected.

1686. Several commenters oppose the right-sizing reform. They suggest that adopting the reform would harm competition or existing transmission planning processes that already evaluate whether replacement transmission facilities can be increased in transfer capability. We are unpersuaded by these arguments. We adopt the right-sizing reform because it captures certain transmission planning efficiencies by addressing aging transmission infrastructure issues while also providing an opportunity to increase transfer capability (*i.e.,* develop the right-sized replacement transmission facility) to address Long-Term Transmission Needs more efficiently or cost-effectively. With respect to concerns about the right-sizing reform's impact on competition, we address that issue below under the section on Rights of First Refusal. Regarding commenters' arguments that existing transmission planning processes already evaluate whether replacement transmission facilities can be right-sized, we note that we require transmission providers to consider right-sizing as part of Long-Term Regional Transmission Planning. If transmission providers wish to continue to consider right-sizing opportunities in some or all of their existing transmission planning processes in addition to Long-Term Regional Transmission Planning, this reform does not address those processes, and they may continue to adhere to existing practices that are not modified by this final order. Further, we emphasize that transmission providers may propose compliance approaches that are consistent with or superior to these requirements, and as such, depending on their individual circumstances and approaches, may be able to demonstrate that a method akin to their existing practice is also appropriate for right-sizing in Long-Term Regional Transmission Planning.

1687. In response to PJM States' request for clarification regarding the interaction between existing processes and whether the right-sizing reform necessitates competitive transmission development processes, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. Regarding PJM States' request for clarification on competitive transmission development processes, we refer to the Right of First Refusal section below.

1688. In response to Exelon's concerns regarding the timing of replacement transmission facilities, we clarify that the 10-year timeframe associated with the right-sizing reform applies to transmission facilities that a transmission provider *anticipates* replacing. In other words, the requirement for a transmission provider to include in its in-kind replacement estimates any transmission facilities that it anticipates replacing in-kind during the next 10 years does not create an obligation for the transmission provider to change any existing process that it has to identify which transmission facilities it anticipates replacing. However, a transmission provider must include in its in-kind replacement estimates any transmission facilities it anticipates replacing during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle, regardless of the process it uses to identify the facilities.

1689. In response to SERTP Sponsors and PG&E's arguments that replacement decisions may be triggered more by the conditions of a particular transmission facility than its age, we reiterate, consistent with the statement the Commission made in the NOPR, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining, and when necessary,

[3585] For example, the maximum 200 kV threshold that we adopt here mirrors existing processes (*e.g.,* CAISO) for determining whether a transmission facility provides regional benefits or more localized benefits. Appendix A of CAISO's OATT defines a ''Large Project'' as ''[a] transmission upgrade or addition that exceeds $200 million in capital costs and consists of a proposed transmission line or substation facilities capable of operating at voltage levels greater than 200 kV.'' CAISO, CAISO eTariff, app. A, Definitions (0.0.0), section Large Project. Moreover, we note that a 200 kV threshold aligns with the 200 kV threshold for interconnection reforms discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Process section of this final order.

[3586] *ExxonMobil Gas Mktg. Co.* v. *FERC,* 297 F.3d 1071, 1085 (D.C. Cir. 2002) (quoting *AT&T Corp.* v. *FCC,* 220 F.3d 607, 627 (D.C. Cir. 2000)).

[3587] ISO–NE Initial Comments at 39.

[3588] NOPR, 179 FERC ¶ 61,028 at P 406.

replacing existing transmission facilities. We recognize that, as SERTP Sponsors note, replacement decisions may be triggered by other conditions than a transmission facility's age or condition, and since we recognize that a transmission provider may have existing rights and responsibilities under existing laws with respect to maintaining and, when necessary, replacing transmission facilities, we note that SERTP Sponsors, as well as any other transmission providers, may address such replacements of existing transmission facilities according to their existing processes.

1690. In response to Entergy's request for clarification regarding storm-hardening, we reiterate that the right-sizing reform we adopt here pertains to transmission facilities that a transmission provider anticipates replacing with an in-kind replacement transmission facility. To the extent that storm-hardening transmission projects do not encompass the replacement of existing transmission facilities with an in-kind replacement transmission facility, those storm-hardening transmission projects need not be included on a transmission provider's list of in-kind replacement estimates.

1691. In response to US DOE's argument that transmission providers should not be required to submit every in-kind replacement for all equipment, we clarify that the right-sizing reform we adopt here requires transmission providers to list in their in-kind replacement estimates *only* the transmission facilities operating at and above the specified kV threshold that they own and anticipate replacing in-kind with a new transmission facility during the next 10 years, provided transmission providers may not propose a specified kV threshold higher than 200 kV.

1692. WIRES requests that the Commission clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities lower than 230 kV if existing transmission planning processes already do so. We clarify that, given our modification to the NOPR proposal, transmission providers may propose on compliance a threshold lower than 200 kV for considering right-sizing transmission facilities. We reiterate that the 200 kV threshold is a maximum threshold (*i.e.,* transmission providers may not propose a right-sizing threshold higher than 200 kV).

2. Right of First Refusal

a. NOPR Proposal

1693. In the NOPR, the Commission proposed, for any right-sized replacement transmission facility that is selected to meet transmission needs identified through Long-Term Regional Transmission Planning, to require the establishment of a Federal right of first refusal for the transmission provider that includes the in-kind replacement transmission facility in its in-kind replacement estimates, which would extend to any portion of such a transmission facility located within the applicable transmission provider's retail distribution service territory or footprint.[3589]

b. Comments

1694. Some commenters support the proposed Federal right of first refusal for right-sized replacement transmission facilities.[3590] AEP argues that without it, transmission providers may develop an in-kind replacement facility instead of the right-sized transmission facility identified in the regional transmission planning process.[3591] Similarly, PG&E states that providing a Federal right of first refusal for right-sized replacement transmission facilities will provide an incentive for transmission providers to develop such projects, where appropriate.[3592]

1695. MISO TOs argue that, whether through in-kind replacement or right-sized replacement, "what is being done is an upgrade of an existing transmission facility," for which the Commission has afforded transmission owners Federal rights of first refusal through Order No. 1000 (and prior actions).[3593] US Chamber of Commerce states that a Federal right of first refusal for right-sized replacement transmission facilities should also apply to right-sized transmission facilities, as it would eliminate incentives to withhold in-kind replacements from the regional transmission planning process.[3594]

1696. Ameren states that critics of the NOPR's proposal to provide transmission providers a Federal right of first refusal for right-sizing projects question whether the Commission has met its FPA section 206 burden to demonstrate that the regional transmission planning tariffs are currently unjust and unreasonable or unduly discriminatory in order to justify this proposal.[3595] Ameren contends that this argument misses a critical point because, currently, replacement of transmission facilities in-kind is generally not subject to the regional transmission planning process or competitive transmission development processes. Ameren asserts that the Commission need not find any existing rate unjust and unreasonable in order to signal an intent to approve such right of first refusals for right-sizing projects when filed with the Commission under FPA section 205.[3596]

1697. Several commenters oppose the proposed Federal right of first refusal for right-sized replacement transmission facilities.[3597] Massachusetts Attorney General argues that the Commission has not demonstrated a "rational connection" between the Commission's findings and the right-sizing reform. Massachusetts Attorney General adds that the NOPR proposal is directly at odds with the Commission's findings in Order Nos. 890 and 1000 and that the Commission fails to provide "good reasons" for departing from those prior findings.[3598] American Municipal Power argues that, even if incumbent transmission owners currently have a right of first refusal for local transmission facilities, that right should be limited to maintenance (*i.e.,* in-kind replacements) and not situations where a transmission facility would expand or

[3589] *Id.* PP 408–409.

[3590] AEP Initial Comments at 46–47; Ameren Reply Comments at 14–15; Dominion Initial Comments at 75; EEI Initial Comments at 41; Exelon Initial Comments at 58; MISO TOs Initial Comments at 27–28; PG&E Reply Comments at 15–16; US Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

[3591] AEP Initial Comments at 46–47 (citing NOPR, 179 FERC ¶ 61,028 at PP 408–409).

[3592] PG&E Reply Comments at 16.

[3593] MISO TOs Initial Comments at 27–28.

[3594] US Chamber of Commerce Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at P 409).

[3595] Ameren Reply Comments at 14 (citing LS Power Initial Comments at 50).

[3596] *Id.*

[3597] AEE Reply Comments at 31; American Municipal Power Initial Comments at 28–29; Anbaric Initial Comments at 7; California Commission Initial Comments at 115–117; California Water Initial Comments at 8–9; City of New York Initial Comments at 11–13; Competition Coalition Initial Comments at 64; Competition Coalition Reply Comments at 2; Industrial Customers Initial Comments at 4; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 22, 25–26, 84–85; Massachusetts Attorney General Initial Comments at 51–53; NextEra Initial Comments at 54–61; Northwest and Intermountain Initial Comments at 21–22; Pennsylvania Commission Initial Comments at 22–23; R Street Initial Comments at 3–4, 12–21; Resale Iowa Initial Comments at 8–9; TAPS Initial Comments at 68.

[3598] Massachusetts Attorney General Initial Comments at 40, 51 (citing 5 U.S.C. 706(2); 16 U.S.C. 825*l*(b); *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n of the U. S.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983)).

enhance the transmission system.[3599] LS Power argues that the right-sizing proposal changes definitions in Order No. 1000, including the definitions of an upgrade and a local transmission facility, and allows a Federal right of first refusal for transmission facilities located on an existing right-of-way instead of leaving the issue to state law.[3600] LS Power asserts that, even if the Commission could meet the first prong of its section 206 analysis and find that the existing transmission planning process is unjust and unreasonable, the Commission must still establish that the entirety of the replacement rate is just and reasonable which, LS Power argues, the Commission cannot because of the tie to a Federal right of first refusal. Taken together, LS Power argues that the NOPR proposal, if adopted, would fail as a replacement rate.[3601] Furthermore, LS Power argues that the Federal right of first refusal for right-sized replacement transmission facilities would essentially provide a Federal franchise, mandating that transmission customers accept the ownership right of the existing transmission owners to continue in perpetuity.[3602]

1698. Northwest and Intermountain support clarifying that a Federal right of first refusal for right-sized replacement transmission facilities does not apply to any facilities that replace equipment that has reached the end of its useful life. Moreover, Northwest and Intermountain contend that the Commission should require a competitive solicitation for any right-sized transmission projects that meet regional transmission needs.[3603] AEE contends that the record does not support further action on the proposed Federal right of first refusal for right-sized replacement transmission facilities, and instead reflects the complexity of the issues involved and the need for a holistic review of competitive transmission development processes and options for improving them.[3604]

1699. Several commenters raise concerns about the incentives that the proposed ederal right of first refusal for right-sized replacement transmission facilities would introduce.[3605] Pennsylvania Commission argues that incumbent transmission owners may use it as a new tool to avoid competition by displacing other regional transmission facilities.[3606] Given that transmission providers may not secure cost recovery for imprudently incurred expenses, NextEra disagrees that, without a Federal right of first refusal for right-sized replacement transmission facilities, incumbent transmission owners may engage in duplicative or inefficient transmission development.[3607]

1700. Some commenters oppose the proposed Federal right of first refusal for right-sized replacement transmission facilities because they argue that it would increase costs for customers.[3608] California Water argues that allowing a Federal right of first refusal for right-sized replacement transmission facilities would permit incumbent transmission owners to construct right-sized transmission facilities without any cost guardrails, which could end up being more expensive than the in-kind replacements.[3609] Alternatively, some commenters argue that their existing transmission planning processes already consider ''right-sizing'' replacement transmission facilities and may not include a Federal right of first refusal.[3610]

1701. In response to claims that there is no logical basis for a Federal right of first refusal for right-sized replacement transmission facilities, MISO TOs state that the proposal applies to upgrades of an existing transmission facility and that in Order No. 1000, the Commission expressly reserved a Federal right of first refusal for an individual utility to upgrade its own property. As such, MISO TOs argue, a right-sizing requirement should neither deprive a transmission owner of its rights regarding its own property or its right to construct and own upgrades to its own system, nor should it implement an unconstitutional taking of such owner's property.[3611] Therefore, MISO TOs state that the final order should clarify that nothing in the right-sizing proposal eliminates an incumbent transmission owner's Federal right of first refusal for any transmission facilities selected through a right-sizing process.[3612]

c. Commission Determination

1702. We adopt the NOPR proposal to require the establishment of a Federal right of first refusal for a right-sized replacement transmission facility[3613] that is selected to meet Long-Term Transmission Needs. This Federal right of first refusal will apply to the transmission provider that included in its in-kind replacement estimate the existing transmission facility that the right-sized replacement transmission facility would replace, and extends to any portion of the right-sized replacement facility located within that transmission provider's retail distribution service territory or footprint, recognizing that any such portion must satisfy the definition of a right-sized replacement facility, as revised by this final order, including that the right-sized replacement transmission facility is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility.

1703. In adopting the NOPR proposal to require the establishment of a Federal right of first refusal for a right-sized replacement transmission facility, we find that permitting a Federal right of first refusal for right-sized replacement

[3599] American Municipal Power Initial Comments at 28.

[3600] LS Power Initial Comments at 22.

[3601] *Id.* at 147–48 (citing *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 845 (D.C. Cir. 2006); *SEC* v. *Chenery Corp.,* 318 U.S. 80, 95 (1943)).

[3602] *Id.* at 84–85.

[3603] Northwest and Intermountain Initial Comments at 21–22.

[3604] AEE Reply Comments at 31.

[3605] Anbaric Initial Comments at 7; California Commission Initial Comments at 114–115; Competition Coalition Initial Comments at 65–67; LS Power Initial Comments at 81–82; Massachusetts Attorney General Initial Comments at 51–52; NextEra Initial Comments at 58; Pennsylvania Commission Initial Comments at 22; Resale Iowa Initial Comments at 8–9.

[3606] Pennsylvania Commission Initial Comments at 22.

[3607] NextEra Initial Comments at 59–61 (citations omitted).

[3608] *See* California Commission Initial Comments at 117; California Water Initial Comments at 9; Competition Coalition Initial Comments at 66–67; DC and MD Offices of People's Counsel Initial Comments at 47–48; R Street Reply Comments at 5–6; State Agencies Initial Comments at 21–22.

[3609] California Water Initial Comments at 9.

[3610] CAISO Initial Comments at 47–49; New York Commission and NYSERDA Initial Comments at 15–16; New York TOs Initial Comments at 17–18; NYISO Initial Comments at 58–59.

[3611] MISO TOs Reply Comments at 33 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 226, 319; Order No. 1000–A, 139 FERC ¶ 61,132 at P 426; *N.Y. Indep. Sys. Operator, Inc.,* 175 FERC ¶ 61,038, at PP 30, 33 (2021)).

[3612] MISO TOs Reply Comments at 33 (citing MISO TOs Initial Comments at 25–28).

[3613] As noted above, right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (*e.g.,* redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (*e.g.,* advanced conductor technologies). Additionally, we reiterate that, as noted above, a right-sized replacement transmission facility is, for purposes of this right-sizing reform, a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate.

transmission facilities will encourage transmission providers to provide their best in-kind replacement estimates, because they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. As such, we find that a Federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning, helping to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and likely built, and therefore that Commission-jurisdictional rates are just and reasonable. Moreover, we note that the definitions of ''in-kind replacement transmission facility'' and ''right-sized replacement transmission facility'' that we adopt, as discussed above, are necessary to ensure that use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.[3614]

1704. We note that the establishment of a Federal right of first refusal for right-sized replacement transmission facilities is an exception to Order No. 1000's general requirement for transmission providers to eliminate any Federal right of first refusal for regional transmission facilities selected in a regional transmission plan.[3615] In response to comments challenging this approach as violating the precedent set in Order No. 1000, which eliminated Federal rights of first refusal for new selected transmission facilities,[3616] we find that requiring a Federal right of first refusal for right-sized replacement transmission facilities aligns with Order No. 1000.

1705. In Order No. 1000, the Commission required transmission providers to remove Federal rights of first refusal from their OATTs because they undermined the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level, which could lead to unjust and unreasonable rates for Commission-jurisdictional services.[3617] The Commission found that Federal rights of first refusal created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level.[3618] The Commission did not require the elimination of Federal rights of first refusal for local transmission facilities,[3619] and did not alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to its own transmission facilities, regardless of whether the upgrade is selected.[3620]

1706. We find that the Commission's reasons for removing Federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities. Specifically, requiring a Federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level; rather, we find that it will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. When compared against the alternative of piecemeal development of in-kind replacement transmission facilities, a Federal right of first refusal for right-sized transmission facilities does not frustrate the goals of Order No. 1000 or lead to inefficiency in transmission development because the right-sized replacement transmission facility represents the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs (otherwise it would not be selected). We recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing their transmission facilities. Because the right-sizing reform does not alter existing laws related to an individual transmission provider's ability to proceed with an in-kind replacement transmission facility, absent a Federal right of first refusal, we believe the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely proceed to develop the less efficient or cost-effective in-kind replacement transmission facility. We find that the transmission provider would prefer the assurance of a Federal right of first refusal for the in-kind replacement transmission facility over the uncertainty of subjecting a right-sized replacement transmission facility to the Order No. 1000 competitive transmission development process. Because of this incentive structure and the fact that the transmission provider holds the leverage as to whether to build a right-sized replacement transmission facility or a less efficient in-kind replacement transmission facility, the establishment of the Federal right of first refusal is necessary to effectuate this reform and ensure that Commission-jurisdictional rates are just and reasonable.[3621]

1707. By establishing a process that requires transmission providers to evaluate opportunities to right-size in-kind replacement transmission facilities to meet Long-Term Transmission Needs, and by establishing a Federal right of first refusal for such right-sized replacement transmission facilities, we believe that the right-sizing reform in this final order will encourage transmission providers to provide their best in-kind replacement estimates, as they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. Moreover, permitting a Federal right of first refusal for right-sized replacement transmission facilities will enable transmission providers to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and that Commission-jurisdictional rates are consequently just and reasonable.[3622]

1708. In response to MISO TOs' request regarding upgrades to existing transmission facilities, we reiterate that nothing in the right-sizing reform affects the right of an incumbent transmission provider to build, own, and recover the costs for upgrades to its own transmission facilities, regardless of whether an upgrade to an existing transmission facility has been identified through a right-sizing process and selected to address Long-Term Transmission Needs.

1709. We deny Northwest and Intermountain's request to clarify that the right-sizing reform excludes transmission facilities that replace equipment that has reached the end of its useful life. As explained above, the Federal right of first refusal will apply to selected right-sized replacement

[3614] *See supra* PP 1681–1683.

[3615] *See supra* P 1576.

[3616] Order No. 1000, 136 FERC ¶ 61,051 at P 313.

[3617] *Id.* PP 253, 256.

[3618] *Id.* P 257.

[3619] *Id.* P 318.

[3620] *Id.* P 319 (citation omitted).

[3621] *See* NOPR, 179 FERC ¶ 61,028 at P 408 & n.652.

[3622] In response to those commenters who argue that their existing transmission planning processes already consider ''right-sizing'' replacement transmission facilities without the inclusion of a Federal right of first refusal, we note that, separate from compliance with this final order, transmission providers in each transmission planning region can agree to participant funding arrangements for right-sized replacement transmission facilities that are not selected through Long-Term Regional Transmission Planning, in which case the requirement to establish a Federal right of first refusal for right-sized replacement transmission facilities selected to meet Long-Term Transmission Needs would not apply.

transmission facilities, including those that are intended to replace transmission facilities that have reached the end of their useful life.

3. Cost Allocation

a. NOPR Proposal

1710. With respect to cost allocation, the Commission proposed that if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method. The Commission proposed that the costs the incumbent transmission provider would have otherwise incurred to construct the in-kind replacement transmission facility be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement. The Commission preliminarily found that it is just and reasonable and not unduly discriminatory or preferential for only the portion of the costs associated with a right-sized replacement transmission facility that is selected to be eligible to use the Long-Term Regional Transmission Cost Allocation Method because it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet the transmission needs identified in Long-Term Regional Transmission Planning.[3623]

1711. The Commission also proposed to require transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected (and thus found to be a more efficient or cost-effective transmission facility to meet regional transmission needs) and which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.[3624]

b. Comments

1712. Some commenters support the NOPR proposal that the incremental costs of right-sizing a transmission facility that is selected would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method.[3625] ACEG contends that without it, a large amount of new transmission investment—directed solely at replacement facilities—will be outside of Long-Term Regional Transmission Planning and thus not given an opportunity to contribute to the grid's overall efficiency and cost-effectiveness.[3626] Eversource asserts that, in New England, asset condition projects receive regional cost allocation, and requests clarification that the Commission is not proposing to disturb the existing cost allocation method for asset condition projects in ISO–NE that are not selected for right-sizing in Long-Term Regional Transmission Planning.[3627] NESCOE recommends that the Commission require transmission providers to explain on compliance the method that they will use to determine the incremental costs of right-sizing a replacement transmission facility. In addition, NESCOE supports the proposal to require transmission providers to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected.[3628]

1713. Other commenters support the proposed cost allocation for right-sized replacement transmission facilities, but express reservations.[3629] Entergy asserts that the Commission should clarify that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation.[3630] With regard to incremental costs, CTC Global urges the Commission to require the transmission planning process to be based on future needs, future benefits, total lifecycle costs, and total benefits for the life of the resource. More specifically, CTC Global suggests that when considering incremental costs, the Commission should consider including energy savings, generating capacity reduction benefits, and resulting reductions in greenhouse gas emissions as benefits associated with the right-sized replacement transmission facility.[3631]

1714. Dominion states that it may be difficult to quantify and allocate the incremental costs of right-sizing a replacement transmission facility.[3632] MISO agrees, stating that it will be challenging to identify the portion of costs that should be recovered as part of the age and condition upgrade using one cost allocation method and a different cost allocation for the portion of the right-sized upgrade identified as part of Long-Term Regional Transmission Planning. MISO argues that this complexity will continue going forward given that the accounting for two types of cost allocation to different customers will have to be tracked for each right-sized replacement transmission facility.[3633]

1715. Some commenters oppose the NOPR proposal.[3634] LS Power argues that the proposal violates cost causation principles as it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of beneficiary analysis.[3635] Indicated PJM TOs state that the Commission should not impose any requirements with respect to the cost allocation of right-sized replacement transmission facilities and instead should provide transmission providers with the flexibility to determine a cost allocation method.[3636] Exelon agrees, adding that the Commission's proposed approach creates unnecessary complications and adds a further variable (base versus incremental cost) to the already complex and often contentious cost allocation process. According to Exelon, the proposal (1) incorrectly assumes that a transmission owner has identified an in-kind replacement transmission facility and its cost; (2) incorrectly assumes that a perfect overlap exists between the displaced transmission facility (or need) and the right-sized replacement transmission facility; and (3) fails to address adjustments for cost savings or overruns on the right-sized portion of the transmission facility.[3637]

c. Commission Determination

1716. We decline to adopt the NOPR proposal to require that, if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility will be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method, while the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission

[3623] NOPR, 179 FERC ¶ 61,028 at P 410.

[3624] *Id.* P 413.

[3625] ACEG Initial Comments at 57–58; Eversource Initial Comments at 54; NARUC Initial Comments at 65; NESCOE Initial Comments at 81.

[3626] ACEG Initial Comments at 57–58.

[3627] Eversource Initial Comments at 54.

[3628] NESCOE Initial Comments at 81.

[3629] CTC Global Initial Comments at 19; Dominion Initial Comments at 75–76; Entergy Initial Comments at 39; MISO Initial Comments at 87; NRG Initial Comments at 36–37.

[3630] Entergy Initial Comments at 39.

[3631] CTC Global Initial Comments at 19.

[3632] Dominion Initial Comments at 75–76.

[3633] MISO Initial Comments at 87.

[3634] Exelon Initial Comments at 59; Indicated PJM TOs Initial Comments at 47; LS Power Initial Comments at 86–87.

[3635] LS Power Initial Comments at 86–87 (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d 1254, *reh'g denied,* 905 F.3d 671 (D.C. Cir. 2018)).

[3636] Indicated PJM TOs Initial Comments at 47 (citation omitted).

[3637] *See* Exelon Initial Comments at 59 & n.103.

facility must be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement transmission facility. This is because we find persuasive comments that identify the complexities and challenges associated with tracking portions of costs of two different transmission projects through time, as well as allocating the costs of a right-sized replacement transmission facility pursuant to two separate cost allocation methods.[3638] While the approach that the NOPR proposed to require may still be a just and reasonable cost allocation approach for right-sized replacement transmission facilities, should the relevant transmission providers *choose* to take on these challenges and address them adequately, we find it appropriate to provide flexibility to transmission providers to propose a cost allocation method for selected right-sized replacement transmission facilities. However, in providing such flexibility, transmission providers must nevertheless demonstrate on compliance that the cost allocation method for selected right-sized replacement transmission facilities is just and reasonable and not unduly discriminatory or preferential and, consistent with cost causation, allocates costs in a manner that is at least roughly commensurate with the estimated benefits of such facilities.[3639]

1717. Further, we also require transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected, as well as which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.

1718. We disagree with LS Power's assertion that the right-sizing cost allocation method proposed in the NOPR violates cost causation principles because it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of other potential beneficiaries.[3640] The customers of the transmission provider that would be allocated the costs associated with the original in-kind replacement transmission facility would have otherwise been responsible for paying those costs had the in-kind replacement transmission facility not been right-sized. Further, we find that it is not unjust, unreasonable, or unduly discriminatory or preferential that, for a right-sized replacement transmission facility selected, only the portion of the costs associated with right-sizing be eligible to use the Long-Term Regional Transmission Cost Allocation Method. Specifically, we find that it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning. As such, we disagree that allowing only the incremental costs of right-sizing the right-sized replacement transmission facility to be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method would violate cost causation principles.

1719. As we note above, we find merit with respect to commenters' concerns about the difficulty in determining the portion of the costs of a right-sized replacement transmission facility attributable to right-sizing and the complexity in tracking portions of differing cost allocation methods through time. For this reason, to the extent that transmission providers propose to allocate the costs of right-sized replacement transmission facilities pursuant to the cost allocation method described in the NOPR, we require the transmission providers to explain on compliance (1) the method that they will use to determine the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, and (2) the method by which they will track the portion of costs over time that are allocated in accordance with the Long-Term Regional Transmission Cost Allocation Method (or, if adopted, subject to a State Agreement Process), as well as the portion of costs that would have been allocated pursuant to the cost allocation method that otherwise would have applied to the in-kind replacement transmission facility. We believe that transmission providers are best positioned to determine both the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, as well as how to best track these costs over time for purposes of cost allocation.

1720. In response to Eversource and Entergy's requests that the Commission clarify the cost allocation method for in-kind replacement transmission facilities that are not selected for right-sizing,[3641] we clarify that we are not requiring any changes pursuant to this right-sizing requirement that would affect the existing cost allocation method(s) for in-kind replacement transmission facilities that are not identified for right-sizing, or for the costs of the underlying in-kind replacement transmission facilities that would have been incurred absent right-sizing. Similarly, in response to Entergy's request for clarification that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation, we clarify that the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission facility must be allocated in a manner consistent with the cost allocation method that would have otherwise applied to that facility, which could include a regional cost allocation method.

1721. We also confirm, in response to comments from CTC Global, that benefits associated with a potential right-sized replacement transmission facility to address Long-Term Transmission Needs should be evaluated in the same manner as for any potential regional transmission facility that could address those needs, which includes evaluating all of the costs of, and all of the benefits provided by, the right-sized replacement transmission facility consistent with reforms outlined in this final order.

1722. In response to Exelon's comments that the NOPR proposal relies on incorrect assumptions regarding the transmission provider identifying an in-kind replacement transmission facility and its cost, as well as there being an overlap between the displaced transmission facility and the right-sized replacement transmission facility, we disagree and note that these conditions are prerequisites that serve as the foundation for the right-sizing requirement. Where a transmission provider has not identified an in-kind replacement transmission facility that could be right-sized to address Long-Term Transmission Needs more efficiently or cost-effectively, no basis exists to select a right-sized replacement transmission facility.

[3638] Dominion Initial Comments at 75–76; Exelon Initial Comments at 59; MISO Initial Comments at 87.

[3639] *See ICC* v. *FERC I,* 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 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).

[3640] LS Power Initial Comments at 86–87 (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d 1254).

[3641] Entergy Initial Comments at 39; Eversource Initial Comments at 54.

4. Miscellaneous

a. Comments

1723. Some commenters recommend that the Commission adopt confidentiality safeguards.[3642] AEP and Indicated PJM TOs contend that the Commission must adopt confidentiality provisions to ensure that information related to right-sizing is not shared beyond the regional planning entity because identification of end-of-life transmission facilities demonstrates potential vulnerabilities that could create security and reliability risks and could also provide advantages to competitors.[3643] WIRES argues that the Commission should allow for the transmission owner to provide to the transmission provider a non-public, confidential, non-binding list of transmission facilities that may need to be replaced based on an appropriate time horizon as determined by the transmission provider.[3644] SERTP Sponsors request that the Commission protect CEII information for transmission facilities that are anticipated to be replaced.[3645]

1724. Conversely, PJM States request that the Commission require the information on the in-kind replacement estimate list to be non-confidential to the greatest extent possible or to require justification as to why confidentiality is merited.[3646]

1725. Several commenters call for the Commission to increase scrutiny on, or alter the presumption of prudence for, transmission projects related to the right-sizing reform.[3647] American Municipal Power argues that if an incumbent transmission owner replaces local transmission facilities at the end of their useful lives despite a determination that a right-sized replacement transmission facility is the more efficient or cost-effective transmission solution, the incumbent transmission owner's in-kind replacement should be presumed to be unjust and unreasonable for purposes of cost recovery.[3648]

1726. ACEG asserts that the Commission has the authority under FPA section 205 to review replacement transmission facility projects and address problems in the local transmission planning process.[3649] LS Power argues that the Commission should use its existing authority to confirm through show cause orders that transmission providers are evaluating whether local transmission solutions can be displaced by a regional transmission solution that is more efficient or cost-effective.[3650]

1727. Similarly, TAPS asserts that the NOPR imposes no consequences on transmission owners that proceed with in-kind replacement projects even when the transmission planning region has selected more efficient and cost-effective alternatives for regional cost allocation. TAPS argues that the Commission should exclude cost recovery for such facilities from the scope of formula rates and require transmission owners to make a separate filing pursuant to FPA section 205. Alternatively, TAPS states that the Commission should impose a presumption of imprudence and require such transmission owners to demonstrate that the proposed replacement is more cost-effective and efficient than the alternative selected by the transmission planning region.[3651]

1728. On the other hand, PG&E argues that the Commission should clarify that a transmission owner's right to decline to proceed with a selected right-sized replacement transmission facility does not justify disallowance of cost recovery for the in-kind replacement transmission facility.[3652]

1729. Several commenters support consideration of alternative transmission technologies and grid enhancing technologies when evaluating right-sized replacement transmission facilities.[3653] CTC Global urges the Commission to require all transmission owners with a line requiring in-kind replacement within 10 years to analyze whether a transmission line's conductor should be replaced with an advanced conductor through rebuild or reconductoring.[3654] PIOs argue that right-sizing opportunities should include increasing voltage, adding circuits, and utilizing advanced technologies, and further argue that right-sized replacement transmission facilities that use grid enhancing technologies can create economies of scale to capture public policy and economic benefits in addition to reliability.[3655] VEIR agrees with the Commission's proposal to include advanced conductors in its definition of right-sizing, explaining that superconductors can enable a five-fold increase in the power flow capacity of an existing transmission corridor. VEIR therefore urges the Commission to explicitly affirm that the deployment of advanced conductors would constitute right-sizing.[3656]

1730. Some commenters argue that the NOPR's right-sizing proposal is insufficient and call upon the Commission to take further action.[3657] For example, ACEG, American Municipal Power, and California Commission argue that the Commission should expand the scope of the right-sizing proposal.[3658] American Municipal Power argues that the Commission should require RTOs/ISOs to plan for all new transmission facilities that have regional impacts, including: (1) transmission facilities that meet the North American Electric Reliability Corporation Bulk Electric System definition; and (2) transmission projects that will replace an existing transmission facility that was turned over to the RTO/ISO irrespective of the voltage.[3659] Similarly, LS Power argues that the Commission has the authority to require regional transmission planning for existing transmission facilities reaching the end of operational life, and that such transmission

[3642] AEP Initial Comments at 46; Exelon Initial Comments at 57–58; Indicated PJM TOs Initial Comments at 45–46; SERTP Sponsors Initial Comments at 39; WIRES Initial Comments at 10.

[3643] AEP Initial Comments at 46; Indicated PJM TOs Initial Comments at 45.

[3644] WIRES Initial Comments at 10.

[3645] SERTP Sponsors Initial Comments at 39.

[3646] PJM States Initial Comments at 7–8.

[3647] American Municipal Power Initial Comments at 29–30; California Commission Initial Comments at 114–115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 5; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 23–24; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6–7, 67–68.

[3648] American Municipal Power Initial Comments at 29.

[3649] ACEG Initial Comments at 57.

[3650] LS Power Initial Comments at 145 (citing LS Power ANOPR Initial Comments at 134–135).

[3651] TAPS Initial Comments at 6–7, 67–68 (citations omitted).

[3652] PG&E Initial Comments at 14.

[3653] CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5–6; NARUC Initial Comments at 58–59; PIOs Initial Comments at 57–58; VEIR Initial Comments at 6.

[3654] CTC Global Initial Comments at 18.

[3655] PIOs Initial Comments at 57–58 (citing PIOs ANOPR Initial Comments at 50).

[3656] VEIR Initial Comments at 6.

[3657] ACEG Initial Comments at 57; American Municipal Power Initial Comments at 25–26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106–108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68–70; Grid United Initial Comments at 3–4; Harvard ELI Initial Comments at 4–5; LS Power Initial Comments at 136, 138, 141–142, 145–146; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64–65.

[3658] *See* ACEG Initial Comments at 57–58; American Municipal Power Initial Comments at 25–26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 113–118.

[3659] American Municipal Power Reply Comments at 5.

planning should be performed by an independent transmission planner.[3660]

1731. Massachusetts Attorney General asserts that all right-sized replacement transmission facilities should be subject to cost containment, stating that transmission owners may present transmission projects that look like good opportunities for right-sizing at low cost, but without cost containment and competition, the final cost could be much higher.[3661] ACEG argues that the Commission could issue policy guidance regarding its scope and process for review of new replacement transmission facilities in transmission rate cases.[3662]

1732. Competition Coalition and LS Power argue that the Commission should protect customers by expanding the benefits of regional transmission planning and competition to all transmission projects 100 kV and above.[3663] Ameren responds that this request by LS Power to expand the range of transmission projects subject to competition is outside the scope of the NOPR.[3664]

1733. Harvard ELI favors additional scrutiny of right-sized replacement transmission facilities. Harvard ELI states generally that the Commission could address the perverse incentives of current rules leading to a focus on local transmission development by subjecting local transmission planning to heightened scrutiny.[3665]

1734. PIOs claim that the Commission should consider an ''ROE subtractor'' analogous to an ROE adder that automatically reduces ROE with certain criteria.[3666]

b. Commission Determination

1735. We decline to adopt ACEG's and LS Power's requests that the Commission *itself* review in-kind replacement transmission facilities, via section 205 or 206 authority or through policy guidance, to ensure that they cannot be displaced by a regional transmission solution that is more efficient or cost-effective.[3667] These arguments are outside the scope of this proceeding because the Commission did not propose in the NOPR that the Commission review in-kind replacement transmission facilities or local transmission facilities.

1736. We decline to adopt commenters' requests for additional confidentiality safeguards related to right-sizing.[3668] We note that a transmission provider's list of in-kind replacement estimates (*i.e.,* estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) is a non-binding estimate and does not require that transmission provider to undertake replacement work. To the extent that customers or stakeholders request access to a transmission provider's list of in-kind replacement estimates, that transmission provider may subject access to that list of in-kind replacement estimates to confidentiality provisions. However, once the transmission providers have determined, as part of Long-Term Regional Transmission Planning, that an in-kind replacement transmission facility can be right-sized to constitute a right-sized replacement transmission facility, we find that the transmission providers must make public the underlying in-kind replacement transmission facility.

1737. We decline to adopt commenter requests for increased scrutiny of, or altering the presumption of prudence for, transmission projects related to right-sizing.[3669] We reject these requests as outside the scope of this proceeding because the Commission did not propose in the NOPR to increase scrutiny of in-kind replacement transmission facilities beyond the right-sizing proposal and did not propose to alter existing Commission policy on prudence. Likewise, in response to PG&E's request for clarification that a transmission provider's declining to proceed with a right-sized replacement transmission facility does not justify disallowance of cost recovery for the in-kind replacement transmission facility, nothing in the reforms we adopt here alters existing Commission policy on cost recovery for transmission facilities.[3670]

1738. We acknowledge commenter support for the consideration of alternative transmission technologies with regard to right-sizing.[3671] However, we find that adopting additional requirements for consideration of alternative transmission technologies with respect to right-sizing are unnecessary. This is because, as discussed in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final order, we require transmission providers in each transmission planning region to more fully consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning, dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching.[3672] We believe that the requirements in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final order adequately address consideration of alternative transmission technologies in the regional transmission planning process, including when considering right-sizing.

1739. Some commenters request that the Commission take other actions and suggest alternative reforms to the Commission's proposal related to right-sizing.[3673] We find these requests to be outside the scope of this proceeding and lacking in record support to adequately

[3660] LS Power Initial Comments at 83–84, 141 (citations omitted).

[3661] Massachusetts Attorney General Initial Comments at 52.

[3662] ACEG Initial Comments at 57 (citation omitted).

[3663] Competition Coalition Initial Comments at 68–69; LS Power Initial Comments at 136, 141 (citations omitted); LS Power and NRG Post-Technical Conference Comments at 10 & n.17 (noting that its comment on this issue is attributed to LS Power only).

[3664] Ameren Reply Comments at 15 (citing LS Power Initial Comments at 116).

[3665] Harvard ELI Initial Comments at 4.

[3666] PIOs Initial Comments at 53.

[3667] ACEG Initial Comments at 57 (citations omitted); LS Power Initial Comments at 145–146 (citing LS Power ANOPR Initial Comments at 134–135).

[3668] AEP Initial Comments at 46; Exelon Initial Comments at 57–58; Indicated PJM TOs Initial Comments at 45–46; SERTP Sponsors Initial Comments at 39; WIRES Initial Comments at 10.

[3669] American Municipal Power Initial Comments at 29–30; California Commission Initial Comments at 114–115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 4; Massachusetts Attorney General Initial Comments at 52; Mississippi Commission Initial Comments at 30; Ohio Consumers Initial Comments at 23; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6–7, 67.

[3670] *New England Power Co.,* 31 FERC ¶ 61,047, at 61,084 (1985) (explaining that the Commission evaluates ''prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses'').

[3671] CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5–6; NARUC Initial Comments at 58–59, 63–64; PIOs Initial Comments at 57–58; VEIR Initial Comments at 6.

[3672] *See* Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section.

[3673] ACEG Initial Comments at 57; American Municipal Power Initial Comments at 5, 25; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106–108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68–69; Grid United Initial Comments at 3–4; Harvard ELI Initial Comments at 4; LS Power Initial Comments at 83, 136, 138, 141–142, 145–146; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64–65.

consider whether to adopt them in this final order.

X. Interregional Transmission Coordination

A. NOPR Proposal

1740. In the NOPR, the Commission proposed to require each transmission provider to revise its existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.[3674]

1741. Specifically, the Commission proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the 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.[3675]

1742. The Commission also proposed to require transmission providers in neighboring transmission planning regions to 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.[3676] The Commission noted that this proposal would align the existing requirement for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located with the proposed requirement for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

1743. The Commission stated that this proposed reform aims to ensure that transmission needs driven by changes in the resource mix and demand identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes.[3677] The Commission preliminarily concluded that the proposed interregional transmission coordination reforms will also ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively meet the transmission needs identified through Long-Term Regional Transmission Planning, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

B. Comments

1744. Many commenters support the Commission's proposal to require transmission providers to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.[3678] Such commenters assert that this proposed reform would give transmission providers in neighboring transmission planning regions the opportunity to consider whether interregional transmission facilities could meet the transmission needs identified through Long-Term Regional Transmission Planning in a more efficient or cost-effective manner than separate regional transmission facilities, which would help to ensure just and reasonable rates.

1745. Some commenters condition their support on the Commission providing transmission providers with flexibility. For example, EEI asserts that providing transmission providers with flexibility in developing Long-Term Regional Transmission Planning will help ensure that transmission planning regions can determine the processes that work for them and collaborate with neighboring regions.[3679] Idaho Power requests that the Commission allow flexibility in the methods used to determine transmission benefits.[3680] Pennsylvania Commission conditions its support on the Commission maintaining flexibility for transmission providers to define criteria for considering and selecting transmission facilities, including criteria that permit the selection of proposed regional transmission facilities over a proposed interregional transmission facility.[3681]

1746. Other commenters suggest that the Commission could improve the proposed reforms to interregional transmission coordination by requiring additional information sharing. For example, U.S. DOE recommends that the Commission require neighboring transmission planning regions to share information with one another about their geographic zones.[3682] California Energy Commission recommends that transmission providers be required to share with neighboring transmission planning regions how other planning processes, such as integrated resource plans, resource adequacy, and state requirements, are considered in regional transmission planning.[3683] State Agencies suggest that transmission providers should provide an annual report to the Commission on their interregional transmission coordination activities, including the number of interregional transmission projects identified, the results of the cost/benefit evaluation overall and to each transmission planning region, whether other regions have been or should be included to maximize the value of the project, and any barriers to development of interregional transmission projects.[3684] NARUC urges the Commission to encourage additional coordination and information sharing between non-RTO/ISO transmission planning regions like NorthernGrid and WestConnect.[3685]

1747. Pattern Energy asserts that the Commission should require neighboring transmission planning regions to hold forums for stakeholders to discuss right-

[3674] NOPR, 179 FERC ¶ 61,028 at P 426.

[3675] *Id.* P 427.

[3676] *Id.* P 428.

[3677] *Id.* P 429.

[3678] Acadia Center and CLF Initial Comments at 23–24; ACEG Initial Comments at 74; Ameren Initial Comments at 47; Arizona Commission Initial Comments at 10; BP Initial Comments at 13–14; Breakthrough Energy Initial Comments at 2; California Commission Initial Comments at 118–121; California Energy Commission Initial Comments at 4; California Water Initial Comments at 20–21; Clean Energy Associations Initial Comments at 40–42; EEI Initial Comments at 48; Enel Initial Comments at 4–5; Eversource Initial Comments at 55–56; Exelon Initial Comments at 60–61; Grid United Initial Comments at 7–9; Idaho Power Initial Comments at 13; Indiana Commission Initial Comments at 7–9; Interwest Initial Comments at 18–20; MISO Initial Comments at 88–89; NARUC Initial Comments at 67–70; National and State Conservation Organizations Initial Comments at 1–2; Northwest and Intermountain Initial Comments at 10, 22; OMS Initial Comments at 18–20; Pennsylvania Commission Initial Comments at 23–25; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–79; PJM Initial Comments at 9–10, 123–125; R Street Initial Comments at 4–5; State Agencies Initial Comments at 22–23; State Officials Supplemental Comments at 1 (citing U.S. Climate Alliance Initial Comments at 3); U.S. Climate Alliance Initial Comments at 3; U.S. DOE Initial Comments at 38–40; U.S. DOJ and FTC Initial Comments at 19–20.

[3679] EEI Initial Comments at 48.

[3680] Idaho Power Initial Comments at 13.

[3681] Pennsylvania Commission Initial Comments at 24–25.

[3682] U.S. DOE Initial Comments at 18–20.

[3683] California Energy Commission Initial Comments at 4.

[3684] State Agencies Initial Comments at 23.

[3685] NARUC Initial Comments at 69–70.

sizing or expanding proposed regional transmission facilities in consideration of the needs of both regions.[3686] Further, Pattern Energy argues that if no interregional transmission facilities are approved in a Long-Term Regional Transmission Planning cycle, the Commission should require transmission planning regions to provide transparent reasoning to help stakeholders and regulators understand whether interregional transmission coordination requires reform.[3687]

1748. MISO asserts that the Commission should institute a separate and longer compliance period for the interregional transmission coordination requirements than for the regional transmission planning requirements proposed in this rulemaking.[3688] Further, to reduce the compliance burden on transmission providers, MISO requests that the Commission include all interregional transmission coordination and planning requirements in a single rulemaking rather than require interregional compliance in multiple, separate proceedings.[3689]

1749. Many commenters assert that the Commission's proposals with respect to interregional transmission coordination do not go far enough.[3690] Several commenters urge the Commission to require holistic interregional transmission planning and cost allocation.[3691] Some commenters encourage the Commission to require a minimum amount of Interregional Transfer Capability between neighboring transmission planning regions.[3692] Several commenters urge the Commission to require neighboring transmission planning regions to adopt a common system model and planning assumptions, common Long-Term Scenarios, and consistent data inputs.[3693] AEP argues that the Commission should require consistency across transmission planning regions in terms of the transmission planning horizon, planning frequency, and minimum set of benefits considered.[3694]

1750. MISO encourages the Commission to examine interregional transmission planning, including analysis of the assumptions related to transfer capacity and the effectiveness of collaboration between RTO and non-RTO neighbors, in a separate docket.[3695] Eversource and State Agencies suggest that the Commission encourage RTOs/ISOs to increase staffing to address interregional transmission planning.[3696] National Grid suggests that the Commission provide appropriate rate incentives for interregional transmission facilities.[3697] Rail Electrification urges the Commission to support the siting of large interregional transmission facilities along available interstate transportation rights-of-way to advance the grid of the future more quickly.[3698]

C. Commission Determination

1751. We adopt, with modification, the NOPR proposal to require transmission providers in each transmission planning region to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in this final order. Specifically, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes, as needed) to provide for: (1) the sharing of information regarding their respective Long-Term Transmission Needs, as well as Long-Term Regional Transmission Facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs.

1752. Additionally, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to 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 Long-Term Transmission Needs. We find that this requirement will align the existing requirement, for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located, with the new requirement in this final order for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

1753. In response to commenter requests for additional information sharing and transparency of the interregional transmission coordination process, we find that additional transparency as applied to Long-Term Regional Transmission Planning is warranted.[3699] Order No. 1000 requires that transmission providers in neighboring transmission planning regions maintain a website or email list for the communication of information related to interregional transmission coordination procedures.[3700] We modify the NOPR proposal, and require transmission providers in each transmission planning region to provide the following additional information concerning Long-Term Regional Transmission Planning on their public website or through the email list used for communication of information related to interregional transmission coordination procedures: (1) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings; (2) any

[3686] Pattern Energy Reply Comments at 14.

[3687] *Id.* at 14–15.

[3688] MISO Initial Comments at 89.

[3689] *Id.* at 88–89.

[3690] *See, e.g.,* ACEG Initial Comments at 76–78; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 41–42; Enel Initial Comments at 4–5; Evergreen Action Initial Comments at 5–6; Eversource Initial Comments at 56; Grid United Initial Comments at 7–8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18–19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12–15; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–77; PJM Initial Comments at 9–10, 123–124; Rail Electrification Initial Comments at 2, 8–11; RMI Initial Comments at 1–2; State Agencies Initial Comments at 23; Transmission Dependent Utilities Initial Comments at 6–7; U.S. DOE Initial Comments at 38–39; Xcel Initial Comments at 17.

[3691] *See, e.g.,* ACEG Initial Comments at 76–78; Clean Energy Associations Initial Comments at 41–42; Enel Initial Comments at 4–5; Evergreen Action Initial Comments at 5–6; Grid United Initial Comments at 7–8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18–19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12–15; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–77; PJM Initial Comments at 9–10, 123–124; Rail Electrification Initial Comments at 2, 8–11; RMI Initial Comments at 1–2; Shell Reply Comments at 8–9; U.S. DOE Initial Comments at 38–39; Xcel Initial Comments at 17.

[3692] *See, e.g.,* ACEG Initial Comments at 70–76; AEP Initial Comments at 17–18; Breakthrough Energy Initial Comments at 2; Evergreen Action Initial Comments at 5–6; Eversource Initial Comments at 55–56; Interwest Initial Comments at 18–20; Invenergy Initial Comments at 20–27; Invenergy Reply Comments at 19–22; Kansas Commission Initial Comments at 4–10; PJM Initial Comments at 9–10, 123–125.

[3693] Hannon Armstrong Reply Comments at 1; Invenergy Reply Comments at 19–22; National Grid Initial Comments at 19–20; Transmission Dependent Utilities Initial Comments at 6–7; U.S. DOE Initial Comments at 18–21.

[3694] AEP Reply Comments at 3–5.

[3695] MISO Reply Comments at 29–30.

[3696] Eversource Initial Comments at 55–56; State Agencies Initial Comments at 23.

[3697] National Grid Initial Comments at 20.

[3698] Rail Electrification Initial Comments at 8–12.

[3699] *See, e.g.,* California Energy Commission Initial Comments at 4; NARUC Initial Comments at 69–70; Pattern Energy Reply Comments at 14–15; State Agencies Initial Comments at 23.

[3700] Order No. 1000, 136 FERC ¶ 61,051 at PP 345, 458.

interregional transmission facilities proposed or identified in response to Long-Term Transmission Needs; (3) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning; (4) the results of any cost-benefit evaluation of such interregional transmission facilities, with such results including both any overall benefits identified (which may occur across multiple transmission planning regions), as well as any benefits particular to each transmission planning region; and (5) the interregional transmission facilities, if any, selected to meet Long-Term Transmission Needs. We find that this modification will enhance transparency and facilitate stakeholder engagement in the interregional transmission coordination procedures as applied to Long-Term Regional Transmission Planning, thereby ensuring just and reasonable rates. We believe that this requirement to make this information publicly available will not create a significant burden because transmission providers will already share or develop such information with the transmission providers in neighboring transmission planning regions to comply with the requirement in this final order to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms.

1754. Taken together, we find that these reforms will ensure that Long-Term Transmission Needs identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes. Further, doing so will ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively address the identified Long-Term Transmission Needs, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

1755. We decline to require the transmission providers in neighboring transmission planning regions to hold forums for stakeholders to discuss right-sizing or expanding proposed regional transmission facilities in consideration of the transmission needs of both regions, as requested by Pattern Energy. The Commission did not propose such a reform in the NOPR, and we decline to require it here.

1756. Regarding Idaho Power's request that the Commission provide transmission providers with flexibility in the methods used to determine the benefits of interregional transmission facilities, we note that this issue is addressed above in the Evaluation of the Benefits of Regional Transmission Facilities section of this final order.[3701] Regarding Pennsylvania Commission's comment that its support for the interregional transmission coordination reforms proposed in the NOPR are conditioned on the Commission maintaining flexibility for transmission providers to define criteria for considering and selecting transmission facilities, we note that the requirements regarding selection criteria are addressed in the section above on the Evaluation and Selection of Long-Term Regional Transmission Facilities.[3702]

1757. Regarding MISO's request for a longer compliance period for transmission providers to comply with the interregional transmission coordination requirements of this final order, we address MISO's request in the Compliance section below.[3703]

1758. With respect to commenter requests for the Commission to: (1) require holistic interregional transmission planning and cost allocation; (2) require a minimum amount of Interregional Transfer Capability between neighboring transmission planning regions; (3) require neighboring transmission planning regions to adopt a common system model, consistent data inputs, and a uniform transmission planning horizon and transmission planning frequency; (4) encourage RTOs/ISOs to increase staffing to address interregional transmission planning; (5) adopt new rate incentives for interregional transmission facilities; and (6) support the siting of large interregional transmission facilities along available transportation rights-of-way, we find such requests to be outside the scope of this proceeding. We recognize that one or more of these reforms hold the potential to enhance system reliability or provide significant consumer benefits. However, the Commission did not propose such reforms in the NOPR, and we decline to adopt them in the final order. However, we note that the Commission currently has an open proceeding in Docket No. AD23–3–000 to consider whether and how to establish a minimum requirement for Interregional Transfer Capability, and may consider further reforms in other proceedings, as appropriate.[3704]

[3701] *See supra* Evaluation of the Benefits of Regional Transmission Facilities section.

[3702] *See supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[3703] *See infra* Compliance Procedures section.

XI. Compliance Procedures

A. NOPR Proposal

1759. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within eight months of the effective date of any final order in this proceeding revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in any final order in this proceeding.[3705] The Commission proposed that transmission providers that are not public utilities would have to adopt the requirements adopted in any final order in this proceeding as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[3706]

1760. Additionally, in the NOPR, the Commission proposed to require transmission providers to demonstrate on compliance that proposed variations from the requirements in the final order are consistent with or superior to the final order.[3707]

B. Comments

1761. Several commenters support a compliance period of eight months or more to allow stakeholders, including Relevant State Entities, sufficient time to negotiate and agree on proposals to comply with this rulemaking.[3708] PJM states that while an eight-month period to submit compliance filings is reasonable, the Commission should thereafter allow time for transmission planners to develop the tools and hire the employees they will need to implement the final order.[3709] NEPOOL states that the Commission should be flexible in considering requests for extensions of time.[3710] Pacific Northwest State Agencies urge the

[3704] *See* Supplemental Notice of Staff-Led Workshop, *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements,* Docket No. AD23–3–000 (Nov. 30, 2022).

[3705] NOPR, 179 FERC ¶ 61,028 at P 430.

[3706] *Id.* P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63).

[3707] *Id.* PP 74–75, 105, 229.

[3708] Idaho Power Initial Comments at 14; ISO–NE Initial Comments at 41; MISO Initial Comments at 90; NARUC Initial Comments at 50–51; NEPOOL Initial Comments at 10; NESCOE Reply Comments at 9 (citing ISO–NE Initial Comments at 41); North Carolina Commission and Staff Initial Comments at 17; Northwest and Intermountain Initial Comments at 22–23; Pacific Northwest State Agencies Initial Comments at 28; PJM Initial Comments at 10, 129.

[3709] PJM Initial Comments at 10, 129.

[3710] NEPOOL Initial Comments at 10.

Commission to provide flexibility rather than a rigid time period of eight months to comply with the final order.[3711]

1762. Certain TDUs argue that the Commission should require transmission providers to submit compliance filings no later than 270 days after the final order becomes effective to reflect the requirements to include an *ex ante* Long-Term Regional Transmission Cost Allocation Method, define benefits, and identify the method by which benefits are selected.[3712]

1763. Some commenters request that the Commission provide longer than eight months to comply with the final order. For example, NARUC argues that eight months is unlikely to allow sufficient time for Relevant State Entities to meaningfully engage.[3713] Given the complexity of the proposals and the need to coordinate with stakeholders, Idaho Power and ISO–NE propose that the Commission allow at least one year for transmission providers to comply with the final order.[3714] For similar reasons, MISO urges the Commission to provide a compliance period of at least 18 months. In addition, to avoid interfering with ongoing transmission expansion efforts in some transmission planning regions, MISO argues that the Commission should allow such regions to propose their own compliance date or instead should state that the final order would not apply to any such ongoing transmission expansion efforts, including MISO's Long-Range Transmission Planning initiative.[3715] Additionally, MISO requests that the new order and tariff revisions complying with the final order be made effective upon the Commission's acceptance of the filing party's compliance filing.[3716]

1764. PJM states that it would be more efficient and less confusing if PJM could first build the long-term model and then comply with the selection and cost allocation requirements at a later date. PJM therefore requests that the Commission clarify whether it is necessary for transmission providers to develop compliance procedures with respect to selection and cost allocation of transmission projects to be selected through Long-Term Regional Transmission Planning before they have had a chance to create and finalize their long-term transmission planning processes.[3717]

1765. MISO asserts that the Commission should allow a separate and longer compliance period for the interregional transmission coordination requirements.[3718]

1766. Separately, MISO states that while the NOPR indicates that the Commission might permit regional flexibility in some areas, it adopts the ''consistent with or superior to'' legal standard for evaluating proposed deviations on compliance.[3719] MISO argues that this standard is too inflexible to achieve the Commission's objectives because it neither recognizes the independent nature of RTOs/ISOs nor has a built-in mechanism to acknowledge legitimate regional differences.[3720] Therefore, MISO recommends that the Commission instead apply a version of the ''independent entity'' variation standard to RTOs/ISOs or otherwise make clear that the proposed reforms contemplate regional flexibility to allow RTOs to retain their best transmission planning practices, particularly those RTOs that are ''early movers'' of the types of reforms in the NOPR.[3721] If the Commission decides not to adopt the independent entity variation standard for this final order, MISO urges the Commission to clarify that it will recognize as ''consistent with or superior to'' any existing regional transmission planning processes that are substantially equivalent to the proposed requirements to avoid impeding progress already made, while compelling reform in transmission planning regions where needed.[3722]

1767. ISO–NE and ISO RTO Council argue that flexibility should extend to determining the rules for inclusion in the tariff, with implementation details in planning procedures or guides, consistent with the Commission's ''rule of reason'' standard.[3723]

C. Commission Determination

1768. We adopt the NOPR proposal, with modification, and require each transmission provider to submit a compliance filing within ten months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets all of the requirements adopted in this final order, except those adopted in the Interregional Transmission Coordination section of this final order. In response to comments from NARUC, Idaho Power, ISO–NE, and MISO requesting a longer compliance timeline, we find that requiring a ten-month compliance period instead of the eight-month compliance period proposed in the NOPR will allow transmission providers to fully develop proposals to comply with this final order and allow stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. As discussed in the Implementation of Long-Term Regional Transmission Planning section, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles). Therefore, transmission providers in each transmission planning region must propose an effective date for the OATT revisions necessary to comply with this final order that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle. However, transmission providers may propose an earlier effective date for some or all parts of their revised OATTs to allow them to begin implementing any aspects of the required reforms sooner than the one-year deadline to commence the first Long-Term Regional Transmission Planning cycle.

1769. We deny PJM's request for clarification to allow a later compliance deadline for the selection and cost allocation requirements of this final order and find it appropriate to require

[3711] Pacific Northwest State Agencies Initial Comments at 28.

[3712] Certain TDUs Initial Comments at 16.

[3713] NARUC Initial Comments at 50–51.

[3714] Idaho Power Initial Comments at 14; ISO–NE Initial Comments at 41.

[3715] MISO Initial Comments at 90–92.

[3716] *Id.* at 90–91; MISO Reply Comments at 32.

[3717] PJM Initial Comments at 98–104.

[3718] MISO Initial Comments at 89.

[3719] MISO Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 74–75).

[3720] MISO Initial Comments at 21–22; MISO Reply Comments at 5.

[3721] MISO Reply Comments at 4. For example, MISO states that its MVP and Long-Range Transmission Plan processes are broadly consistent with the principles and goals of the NOPR and some of its specific proposals, including development of multiple futures, review of various benefit metrics, and use of a 20-year transmission planning horizon. MISO states that repeating the extensive stakeholder effort involved in developing these processes to comply with the new requirements would stall its momentum. MISO Initial Comments at 10.

[3722] MISO Initial Comments at 25; MISO Reply Comments at 8–9.

[3723] ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8–9 (citing *City of Cleveland* v. *FERC,* 773 F.2d. at 1376).

that transmission providers submit a compliance filing that addresses all the requirements of this final order within ten months of the effective date of this final order, with the exception of the requirements related to interregional transmission coordination, as previously noted.

1770. In response to MISO's request for a separate, longer compliance timeline for the interregional transmission coordination requirements, we also modify the NOPR proposal and require each transmission provider to submit a separate compliance filing within 12 months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final order.[3724] We find that the additional time to comply with the interregional transmission coordination requirements will allow transmission providers to coordinate with the transmission providers in each of their neighboring transmission planning regions to develop interregional transmission coordination proposals.

1771. Additionally, we adopt the proposed requirement that transmission providers that are not public utilities must adopt the requirements of this final order as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[3725]

1772. In this final order, we make no changes to the standards used to judge requested variations, as described in Order Nos. 888, 2000, 890, and 1000.[3726] Accordingly, we decline to grant MISO's request that the Commission apply the independent entity variation standard, rather than the ''consistent with or superior to'' standard, for proposed deviations from the requirements in this final order on compliance. Consistent with the Commission's findings in Order No. 890, we will continue to apply the ''consistent with or superior to'' standard in the context of transmission planning.[3727]

1773. Regarding MISO's request for clarification, we decline to clarify as part of this final order that any existing transmission planning processes are consistent with or superior to the requirements in this final order. Rather, it is more appropriate for a transmission provider to submit such a request as part of its compliance filing, in which the transmission provider must demonstrate that any deviation from the requirements of this final order, including any existing processes and/or OATT provisions, are consistent with or superior to the requirements of this final order. Similarly, to the extent that a transmission provider believes that it already complies with any of the requirements of this final order, it should describe in its compliance filing how the relevant requirements are satisfied, including by referencing specific tariff sheets already on file with the Commission.

1774. In response to ISO–NE's and ISO RTO Council's comment that the final order should provide flexibility as to which implementation details should be included in planning procedures or guides consistent with the Commission's ''rule of reason'' standard, we note that the Commission has broad discretion in applying the rule of reason policy,[3728] under which provisions that ''significantly affect rates, terms, and conditions'' of service, are realistically susceptible of specification, and are not generally understood in a contractual agreement, must be included in the tariff. The tariff need not include ''mere implementation details,''[3729] which instead may be included only in the business practice manuals. ''[E]ven specifiable practices that significantly affect rates need not be included if they are clearly implied by the tariff's express terms.''[3730] The final order specifies with respect to each requirement the information that must be incorporated into the transmission provider's OATT. We find that the requirements in this final order regarding what information transmission providers must specify in their tariff on compliance is consistent with the Commission's rule of reason policy.

XII. *Information Collection Statement*

1775. The information collection requirements contained in this final order are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[3731] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[3732] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this final order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

1776. The reforms adopted in this final order revise the Commission's *pro forma* OATT to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements to ensure that Commission-jurisdictional rates and practices are just and reasonable and not unduly discriminatory or preferential.

1777. In the NOPR, the Commission solicited comments on: the Commission's need for this information; whether the information will have practical utility; the accuracy of the burden estimates; ways to enhance the quality, utility, and clarity of the information to be collected or retained; and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission received one comment from PJM specifically about the time and effort required to comply with the information collection requirement.[3733]

1778. PJM claims that the Commission significantly underestimates the cost for PJM and other transmission providers to comply with the final order. PJM states that its compliance will require additional staff of between seven to 14 new staff members and that the added cost will be at least $2.1 million per year. However, PJM adds that it generally supports the proposed reforms in the NOPR and provides this information only to give the Commission a better understanding of the time and costs associated with implementing the final order.[3734]

1779. In response to PJM's comments on the NOPR, we note that this information collection statement estimates the burdens[3735] to generate,

[3724] *See supra* Interregional Transmission Coordination section.

[3725] NOPR, 179 FERC ¶ 61,028 at P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63).

[3726] Order No. 1000, 136 FERC ¶ 61,051 at P 815; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769–70.

[3727] Order No. 890, 118 FERC ¶ 61,119 at P 160.

[3728] *Hecate Energy Greene Cnty. 3 LLC* v. *FERC*, 72 F.4th at 1314 (citing *City of Cleveland* v. *FERC*, 773 F.2d at 1376 (the FPA's ''amorphous'' requirement that tariffs include ''practices affecting rates'' means that the Commission has ''broad discretion'' in giving the act ''concrete application.'')).

[3729] *Id.* at 1312.

[3730] *Id.* at 1314 (citing *City of Cleveland* v. *FERC*, 773 F.2d at 1376).

[3731] 44 U.S.C. 3507(d).

[3732] 5 CFR 1320.11.

[3733] PJM Initial Comments at 10, 125–29.

[3734] *Id.* at 128–29.

[3735] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation maintain, retain, or disclose or provide information to or for a Federal agency. In light of the information that PJM supplied, we have revised the table below to increase the estimated amount of labor required for a transmission provider to perform Long-Term Regional Transmission Planning.[3736] We expect that the information collection requirements associated with updating these datasets for subsequent cycles will entail substantially less effort than the initial Long-Term Regional Transmission Planning cycle.

1780. Summary of the Revisions to the Collection of Information due to the final order in Docket No. RM21–17–000:

• *Title:* Electric Transmission Facilities (FERC–917).[3737]

• *Action:* Revision of collections of information in accordance with Docket No. RM21–17–000.

• *OMB Control Nos.:* 1902–0233 (FERC–917).

• *Respondents:* Transmission providers, including RTOs/ISOs.

• *Frequency of Information Collection:* One time during Year 1. Occasional times during subsequent years, at least once every five years.

• *Necessity of Information:* The reforms in this final order will correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

• *Internal Review:* We have reviewed the reforms and have determined that such reforms are necessary. These reforms conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

• *Public Reporting Burden:* The burden and cost estimates below are based on the need for applicable entities to revise documentation, already required by the Commission's *pro forma* OATT. Our estimates are based on the North American Electric Reliability Corporation Compliance Registry as of January 11, 2024, which indicates that there are 48 transmission service providers[3738] with OATTs and 118 transmission owners that are registered within the United States and are subject to this rulemaking.[3739] Because 41 of the 118 transmission owners are also included in the count of 48 transmission service providers, there are 125 distinct entities (*i.e.,* 125 distinct transmission providers[3740 3741 3742]) in total that must comply this final order. We note that, for the purposes of regional transmission planning, these 125 entities are grouped into 11 transmission planning regions.

1781. We estimate that the final order would affect the burden and cost of FERC–917 as follows:

CHANGES DUE TO FINAL ORDER IN DOCKET NO. RM21–17–000[3741]

Area of modification A	Annual number of respondents B	Total annual estimated number of responses C	Average burden hours & cost[3742] per response D	total estimated burden hours & total estimated cost (column C × column D) E
FERC–917, Electric Transmission Facilities (OMB Control No. 1902–0233)				
Draft OATT revisions to comply with the requirements of the final order.	48 transmission providers with OATTs.	48	One Time: 770 hours; $71,683. Ongoing: 0 hours per year; $0 per year.	One Time: 36,960 hours; $3,440,783. Ongoing: 0 hours per year; $0 per year.
Establish a six-month time period during which transmission providers must, among other things, provide a forum for negotiation that enables participation by Relevant State Entities and to discuss potential Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process.	48 transmission providers with OATTs.	48	One Time: 390 hours; $36,307. Ongoing: 0 hours per year; $0 per year.	One Time: 18,720 hours; $1,742,734. Ongoing: 0 hours per year; $0 per year.

of what is included in the information collection burden, refer to 5 CFR 1320.3(b)(1).

[3736] For example, for an entire transmission planning region, we anticipate that 10 people each working 2,000 hours per year would spend 20,000 hours per year to develop these datasets.

[3737] In the NOPR, in addition to proposing to revise the FERC–917 information collection, the Commission proposed to revise the *pro forma* LGIP and, therefore, to revise the FERC–516 information collection (Reform of Generator Interconnection Procedures and Agreements). In this final order, we decline to revise the *pro forma* LGIP, and therefore we are not revising the FERC–516 information collection.

[3738] The transmission service provider (TSP) function is a North American Electric Reliability Corporation registration function, which is similar to the transmission provider that is referenced in the *pro forma* OATT. The TSP function is being used as a proxy to estimate the number of transmission providers that are impacted by this proposed rulemaking.

[3739] The number of entities listed from the North American Electric Reliability Corporation Compliance Registry reflects the omission of the Texas registered entities. Note that the 48 transmission providers with OATTs do not include non-public utility transmission providers with reciprocity tariffs.

[3740] *See supra* note 2.

[3741] In the table, Year 1 figures are one-time implementation hours and cost. ''Subsequent years'' show ongoing burdens and costs starting in Year 2.

[3742] The hourly cost (for salary plus benefits) uses the figures from the Bureau of Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2022, issued April 25, 2023, *http://bls.gov/oes/current/naics2_22.htm*) and benefits (based on BLS data for September 2023; issued December 15, 2023, *http://www.bls.gov/news.release/ecec.nr0.htm*) and are Manager (Occupation Code 11–0000, $122.48/hour), Electrical Engineer (Occupation Code 17–2071, $89.04/hour), and File Clerk (Occupation Code 43–4071, $42.43/hour). The hourly cost for the reporting requirements ($105.76) is an average of the hourly cost (wages plus benefits) of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

CHANGES DUE TO FINAL ORDER IN DOCKET NO. RM21–17–000 [3741]—Continued

Area of modification A	Annual number of respondents B	Total annual estimated number of responses C	Average burden hours & cost [3742] per response D	total estimated burden hours & total estimated cost (column C × column D) E
Participate in Long-Term Regional Transmission Planning, which includes creating and updating datasets, developing Long-Term Scenarios, evaluating the benefits of Long-Term Regional Transmission Facilities, and establishing criteria in consultation with Relevant State Entities and stakeholders to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.	48 transmission providers with OATTs.	48	One Time: 0 hours; $0. Ongoing: 4,500 hours per year; $418,926 per year.	One Time: 0 hours; $0. Ongoing: 216,000 hours per year; $20,108,471 per year.
	77 transmission providers without OATTs.	77	One Time: 0 hours; $0. Ongoing: 200 hours per year; $18,619.	One Time: 0 hours; $0. Ongoing: 15,400 hours per year; $1,433,659 per year.
Revise the regional transmission planning process to enhance transparency of local transmission planning and identifying potential opportunities to right-size replacement transmission facilities.	48 transmission providers with OATTs.	48	One Time: 30 hours; $2,793. Ongoing: 120 hours per year; $11,172 per year.	One Time: 1,440 hours; $134,056. Ongoing: 5,760 hours per year; $536,226 per year.
	77 transmission providers without OATTs.	77	One Time: 20 hours; $1,862. Ongoing: 40 hours per year; $3,724 per year.	One Time: 1,540 hours; $143,366. Ongoing: 3,080 hours per year; $286,732 per year.
Evaluate whether certain alternative transmission technologies can meet the transmission needs identified in Order No. 1000 regional transmission planning processes and in Long-Term Regional Transmission Planning process more efficiently or cost-effectively than transmission facilities without such alternative transmission technologies.	48 transmission providers with OATTs.	48	One Time: 0 hours; $0. Ongoing: 100 hours per year; $9,309 per year.	One Time: 0 hours; $0. Ongoing: 4,800 hours per year; $446,855 per year.
	77 transmission providers without OATTs.	77	One Time: 0 hours; $0. Ongoing: 20 hours per year; $1,862 per year.	One Time: 0 hours; $0. Ongoing: 1540 hours per year; $143,366 per year.
Consider in the Order No. 1000 regional transmission planning processes regional transmission facilities that address certain interconnection-related needs..	48 transmission providers with OATTs.	48	One Time: 0 hours; $0. Ongoing: 50 hours per year; $4,655 per year.	One Time: 0 hours; $0. Ongoing: 2,400 hours per year; $223,427 per year.
Share with the transmission providers in neighboring transmission planning regions information regarding Long-Term Transmission Needs and potential transmission facilities to meet those needs; identify and jointly evaluate interregional transmission facilities with the transmission providers in neighboring transmission planning regions; and publicly post certain information regarding interregional coordination processes applied to Long-Term Regional Transmission Planning..	48 transmission providers with OATTs.	48	One Time: 0 hours; $0. Ongoing: 25 hours per year; $2,327 per year.	One Time: 0 hours; $0. Ongoing: 1,200 hours per year; $111,714 per year.
Total burden for the revisions of FERC 917 due to RM21–17.	48 transmission providers with OATTs.	48	One Time: 1,190 hours; $110,783. Ongoing: 4,795 hours per year; $446,390 per year.	One Time: 57,120 hours; $5,317,573. Ongoing: 230,160 hours per year; *$21,426,693 per year.
1	77 transmission providers without OATTs.	77	One Time: 20 hours; $1,862. Ongoing: 260 hours per year; $24,205 per year.	One Time: 1,540 hours; $143,366. Ongoing: 20,020 hours per year; $1,863,757 per year.
	Totals for all 125 transmission providers			One Time: 58,660 hours; $5,460,939. Ongoing: 250,180 hours per year; $23,290,450 per year.

1782. Our estimates conservatively assume the maximum number of respondents and burdens. We acknowledge that the actual burdens for some respondents may be lower than estimated and that other respondents may incur the maximum burdens.

1783. Interested persons may obtain information on the reporting requirements by contacting Jean Sonneman, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (*DataClearance@ferc.gov*) or telephone (202) 502–8663.

XIII. *Environmental Analysis*

1784. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[3743] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final order under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[3744]

XIV. *Regulatory Flexibility Act*

1785. The Regulatory Flexibility Act of 1980 (RFA) [3745] generally requires a description and analysis of rulemakings that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[3746] RTOs/ISOs, transmission planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 950 employees (including the entity and its associates).[3747]

1786. We have determined that the entities impacted by this final order are transmission providers in transmission planning regions that span across the United States.[3748]

1787. To identify small firms among the transmission providers that comprise the transmission planning regions, we created a list of transmission service providers and transmission owners from the North American Electric Reliability Corporation Registry (dated January 11, 2024), totaling 125 entities. We conducted research using both open-source information and data from paid services such as Dunn & Bradstreet. We find that, out of the population of 125 transmission providers, 18 would be considered small using the SBA threshold (14% rounded). Therefore, we do not consider this number of small entities to be substantial.

1788. As shown in the table above, we estimate the one-time costs associated with the final order to be $110,783 per transmission provider with an OATT and $1,862 per transmission provider without an OATT. We estimate the ongoing costs in subsequent years to be $446,390 per year for transmission providers with an OATT and $24,205 per year for transmission providers without an OATT. Further, we note that Commission regulations allow for transmission providers to fully recover the costs of participating in the regional transmission planning process.[3749] Therefore, we do not believe that this cost is economically significant. Accordingly, we certify that the reforms in this final order will not have a significant economic impact on a substantial number of small entities.

XV. Document Availability

1789. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*https://www.ferc.gov*).

1790. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1791. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

XVI. Effective Date and Congressional Notification

1792. This final order is effective August 12, 2024. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this order is a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Chairman Phillips and Commissioner Clements are concurring with a joint separate statement attached.

Commissioner Christie is dissenting with a separate statement attached.

Issued May 13, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

Note: The following appendices will not appear in the Code of Federal Regulations.

Appendix A: Abbreviated Names of Commenters

ABBREVIATED NAMES OF COMMENTERS

Abbreviation	Commenter(s)
Acadia Center and CLF	Acadia Center and Conservation Law Foundation.

[3743] *Regulations Implementing the Nat'l Env'l Pol'y Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[3744] 18 CFR 380.4(a)(15).

[3745] 5 U.S.C. 601–612.

[3746] 13 CFR 121.201.

[3747] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act, which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. The SBA's regulations define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 950 employees. 13 CFR 121.201; *see* 5 U.S.C. 601(3) (citing section 3 of the Small Business Act, 15 U.S.C. 632).

[3748] *See FERC, Regions Map Printable Version Order No. 1000* (Nov. 9, 2021), *https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.*

[3749] Order No. 890, 118 FERC ¶ 61,119 at P 586.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
ACEG	Americans for a Clean Energy Grid.
ACORE	American Council on Renewable Energy.
Advanced Energy Buyers	Advanced Energy Buyers Group.
AEE	Advanced Energy Economy.
AEP	American Electric Power Service Corporation.
Alabama Commission	Alabama Public Service Commission.
Amazon	Amazon Energy LLC.
Ameren	Ameren Services Company.
American Municipal Power	American Municipal Power, Inc.
Americans for Fair Energy Prices	Americans for Fair Energy Prices, Inc.
Anbaric	Anbaric Development Partners, LLC.
APPA	American Public Power Association.
APS	Arizona Public Service Company.
Arizona Commission	Arizona Corporation Commission.
ATC	American Transmission Company LLC.
Avangrid	Avangrid, Inc.
Bekaert	Bekaert Corporation.
BP	bp America.
Breakthrough Energy	Breakthrough Energy.
Business Council for Sustainable Energy	Business Council for Sustainable Energy.
CAISO	California Independent System Operator Corporation.
California Commission	California Public Utilities Commission.
California Democratic Representatives	U.S. Representatives Jared Huffman; Mike Levin; Nanette Diaz Barragán; Grace F. Napolitano; Anna G. Eshoo; Katie Porter; Judy Chu; Mike Thompson; Ted W. Lieu; Julia Brownley; Mark DeSaulnier; and Juan Vargas.
California Energy Commission	California Energy Commission.
California Municipal Utilities	California Municipal Utilities Association.
California Water	California Department of Water Resources State Water Project.
CARE Coalition	The National Audubon Society; Defenders of Wildlife; Environmental Law & Policy Center; National Wildlife Federation; The Nature Conservancy; Center for Renewables Integration; and Vote Solar, jointly the Conservation and Renewable Energy Coalition.
Center for Biological Diversity	The Center for Biological Diversity.
Ceres	Ceres.
Certain TDUs	Alliant Energy Corporate Services, Inc.; Consumers Energy Company; and DTE Electric Company.
Chemistry Council	American Chemistry Council.
Citizens Energy	Citizens Energy Corporation.
City of New Orleans Council	Council of the City of New Orleans.
City of New York	City of New York.
Clean Energy Associations	The American Clean Power Association; Alliance for Clean Energy—New York; Clean Grid Alliance; the Mid-Atlantic Renewable Energy Council Action; and the New York Offshore Wind Alliance, collectively Clean Energy Associations.
Clean Energy Buyers	Clean Energy Buyers Association.
Clean Energy States	Clean Energy States Alliance.
Colorado Consumer Advocate	Colorado Office of the Utility Consumer Advocate.
Competition Advocates	Niskanen Center; R Street Institute; Institute for Local Self Reliance; Public Citizen, Inc.; Center for Biological Diversity; and Open Markets Institute.
Competition Coalition	Electricity Transmission Competition Coalition.
Concerned Scientists	The Union of Concerned Scientists.
Conservative Energy Network	Conservative Energy Network.
Conservatives for Clean Energy—Florida	Conservatives for Clean Energy—Florida.
Conservatives for Clean Energy—SC	Conservatives for Clean Energy—South Carolina.
Consumer Organizations	NJ Charge, Inc.; Keryn Newman (Stop Path WV); Illinois Landowners Alliance; Block Grain Belt Express—Missouri; Citizens to Stop Transource—York; Coalition for Rural Property Rights; Eastern Missouri Landowners Alliance; Missouri Landowners Association; Protect Sudbury Inc.; Say No to NECEC; Stop B2H Coalition; Eastern Missouri Landowners Alliance; SOUL of Wisconsin; Block RICL; Matthew Stallbaumer; Vickie Husbands; Elena Guardincerri; Martha Peine; Kerry Beheler; Barron Shaw; and STOP Transource Power Lines MD, Inc.
Cross Sector Representatives	Ameren Transmission; Blue-Green Alliance; Consolidated Edison Company of New York, Inc.; Edison International; Exelon Corporation; Greater Warren County Economic Development Council; International Brotherhood of Electric Workers IBEW 1245; IBEW Illinois State Conference; IBEW International; IBEW Sixth District; ITC Holdings Corp.; National Audubon Society; Pacific Gas & Electric Co.; The Permitting Institute; Public Service Electric and Gas Company; WEG Transformers USA; and Xcel Energy.
CTC Global	CTC Global Corporation.
Cypress Creek	Cypress Creek Renewables, LLC.
DATA	Ameren Services Company; Eversource Energy; Exelon Corporation; ITC Holdings Corp.; National Grid USA; Public Service Electric and Gas Company; and Xcel Energy; collectively Developers Advocating Transmission Advancements (DATA).
DC and MD Offices of People's Counsel	The Office of the People's Counsel for the District of Columbia and the Maryland Office of People's Counsel.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Dominion	Dominion Energy Services, Inc.
Duke	Duke Energy Corporation.
Duquesne Light	Duquesne Light Company.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Enel	Enel North America, Inc.
ENGIE	ENGIE North America, Inc.
Entergy	Entergy Services, LLC.
Environmental Groups	Advanced Energy United; American Clean Power Association; Clean Air Task Force; EarthJustice; Environmental Defense Fund; Evergreen Action; Fresh Energy; Interwest Energy Alliance; League of Conservation Voters; National Wildlife Federation; Natural Resources Defense Council; Northwest Energy Coalition; Rewiring America; Sierra Club; Southern Environmental Law Center; The Environmental Law & Policy Center; Union of Concerned Scientists; WE ACT for Environmental Justice; and Western Resource Advocates.
Environmental Legislators Caucus	National Caucus of Environmental Legislators.
EPSA	Electric Power Supply Association.
Evergreen Action	Evergreen Action and 4,440 Individual Signers.
Eversource	Eversource Energy Service Company.
Exelon	Exelon Corporation.
Fervo	Fervo Energy Company.
Form Energy	Form Energy, Inc.
Freeport-McMoRan	Freeport-McMoRan, Inc.
Georgia Commission	Georgia Public Service Commission.
Governor of Kansas Laura Kelly	Governor of the State of Kansas Laura Kelly.
Grand Rapids NAACP	Greater Grand Rapids Chapter of The National Association for the Advancement of Colored People.
Grid United	Grid United LLC.
GridLab	GridLab.
Handy Law	Seth Handy, Handy Law, LLC.
Hannon Armstrong	Hannon Armstrong Sustainable Infrastructure Capital, Inc.
Harvard ELI	Harvard Electricity Law Initiative.
Idaho Commission	The Idaho Public Utilities Commission.
Idaho Power	Idaho Power Company.
Illinois Commission	The Illinois Commerce Commission.
Indiana Commission	Indiana Utility Regulatory Commission.
Indicated PJM TOs	The Dayton Power and Light Company; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, West Penn Power Company, The Potomac Edison Company, Monongahela Power Company, Keystone Appalachian Transmission Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; Rockland Electric Company; and UGI Utilities Inc.
Indicated U.S. Senators and Representatives	U.S. Senators Tina Smith; Edward J. Markey; and Sheldon Whitehouse; U.S. Representatives Kathy Castor; Bobby L. Rush; Paul Tonko; Sean Casten; Raja Krishnamoorthi; Jared Huffman; Veronica Escobar; and Julia Brownley
Industrial Customers	American Forest & Paper Association; the PJM Industrial Customer Coalition; and the Coalition of MISO Transmission Customers, collectively the Industrial Customer Organizations.
Interwest	Interwest Energy Alliance.
Invenergy	Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; and Invenergy Transmission LLC.
Iowa Commission	Iowa Utilities Board.
ISO/RTO Council	The ISO/RTO Council.
ISO–NE	ISO New England Inc.
ITC	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC.
Joint Commenters	American Public Power Association; Electricity Consumers Resource Council; Indiana Office of Utility Consumer Counselor; Large Public Power Council; National Association of State Utility Consumer Advocates; Office of People's Counsel for the District of Columbia; Public Advocate for the State of Delaware; and Solar Energy Industries Association.
Joint Consumer Advocates	Iowa Office of Consumer Advocate and Indiana Office of Utility Consumer Counselor.
Kansas Commission	Kansas Corporation Commission.
Kansas Commission Chair Keen	Kansas Corporation Commission Chairman Dwight D. Keen.
Kansas Ratepayers Advocates	Kansas Industrial Consumers Group, Inc. and Kansans for Lower Electric Rates, Inc.
Kentucky Commission Chair Chandler	Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler.
LADWP	Los Angeles Department of Water & Power.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Large Energy Customers	Akamai Technologies, Inc.; Amazon.com, Inc.; Amy's Kitchen, Inc.; Apple, Inc.; Applied Materials, Inc.; ARC Homes; Atlassian Corporation; Autodesk, Inc.; BASF Corporation; Best Buy Co., Inc.; Brookfield Properties; Budderfly, Inc.; Build Efficiently, LLC.; Cargill, Inc.; Clean Energy Buyers Association; Eastman Chemical Company; eBay, Inc.; Equinix, Inc.; Freeport-McMoRan, Inc.; General Motors LLC; Google LLC; Green Impact Technologies; Hewlett Packard Enterprise Company; Humanscale Corporation; IHG Hotels & Resorts; Marriott International, Inc.; Mars, Inc.; Meta Platforms, Inc.; Microsoft Corporation; Monarch Energy; Nike, Inc.; Nucor Corporation; Oatly Group AB; PepsiCo, Inc.; Prologis, Inc.; Rivian Automotive, Inc.; Saint-Gobain North America; Salesforce, Inc.; Schneider Electric SE; Target Corporation; Thermo Fisher Scientific, Inc.; The STAAC Group, LLC., Walmart, Inc.; Workday, Inc.; and World Energy, LLC.
Large Public Power	The Large Public Power Council.
Louisiana Commission	Louisiana Public Service Commission.
LS Power	LS Power Grid, LLC.
Maine Public Advocate	The Maine Office of the Public Advocate.
Maryland Energy Administration	Maryland Energy Administration.
Massachusetts Attorney General	Massachusetts Attorney General Maura Healey.
Michigan Commission	Michigan Public Service Commission.
Michigan Conservative Energy Forum	Michigan Conservative Energy Forum.
Michigan State Entities	Michigan Attorney General and the Citizens Utility Board of Michigan.
Microgrid Resources	Microgrid Resources Coalition.
Middle River Power	Middle River Power LLC.
Minnesota State Entities	The Minnesota Public Utilities Commission and The Minnesota Department of Commerce.
MISO	Midcontinent Independent System Operator, Inc.
MISO Coops	The Coalition of MISO Generation and Transmission Cooperatives.
MISO TOs	Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
Mississippi Commission	The Mississippi Public Service Commission.
Montana QF Developers	Clēnera, LLC and Greenfields Irrigation District.
Montclair Congregation	40 Undersigned Congregants of Montclair Presbyterian Church.
NARUC	The National Association of Regulatory Utility Commissioners.
NASEO	The National Association of State Energy Officials.
NASUCA	The National Association of State Utility Consumer Advocates.
National and State Conservation Organizations	National Wildlife Federation; Conservation Coalition of Oklahoma; Environment Council of Rhode Island; Environmental League of Massachusetts; Idaho Wildlife Federation; Iowa Wildlife Federation; Kentucky Waterways Alliance; Natural Resources Council of Maine; Nevada Wildlife Federation; New Jersey Audubon; Southeast Alaska Conservation Council; Texas Conservation Alliance; Utah Wildlife Federation; WV Rivers Coalition; and Wyoming Wildlife Federation.
National Grid	National Grid Plc.
Nebraska Commission	The Nebraska Power Review Board.
NEMA	National Electrical Manufacturers Association.
NEPOOL	The New England Power Pool Participants Committee.
NERC	North American Electric Reliability Corporation; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation, Texas Reliability Entity, Inc., and Western Electricity Coordinating Council.
NESCOE	The New England States Committee on Electricity.
Nevada Commission	The Public Utilities Commission of Nevada.
New England for Offshore Wind	New England for Offshore Wind.
New England Systems	Belmont Municipal Light Department; Block Island Utility District; Braintree Electric Light Department; Chicopee Municipal Light Department; Georgetown Municipal Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; North Attleborough Electric Department; Norwood Municipal Light Department; Pascoag Utility District; Reading Municipal Light Department; Stowe Electric Department; Taunton Municipal Lighting Plant; Wallingford Electric Division; and Westfield Gas & Electric Light Department.
New Jersey Commission	The New Jersey Board of Public Utilities.
New Mexico RETA	The New Mexico Renewable Energy Transmission Authority.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
New York Commission and NYSERDA	New York Public Service Commission and New York State Energy Research and Development Authority.
New York State Department	New York State Department of State Utility Intervention Unit.
New York TOs	Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Niagara Mohawk Power Corporation; New York Power Authority; New York State Electric & Gas Corporation; Orange and Rockland Utilities, Inc.; Long Island Power Authority; and Rochester Gas and Electric Corporation.
New York Transco	New York Transco, LLC.
NextEra	NextEra Energy, Inc.
Non-RTO NASUCA	North Carolina Utilities Commission Public Staff; the Utah Office of Consumer Service; the South Carolina Office of Regulatory Staff; and the Wyoming Office of Consumer Advocate.
North Carolina Commission and Staff	The North Carolina Utilities Commission and the North Carolina Utilities Commission Public Staff.
North Dakota Commission	North Dakota Public Service Commission Public Utilities Division.
Northwest and Intermountain	Northwest & Intermountain Power Producers Coalition.
NRECA	National Rural Electric Cooperative Association.
NRG	NRG Energy, Inc.
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority.
Ohio Commission Federal Advocate	The Public Utilities Commission of Ohio's Office of the Federal Energy Advocate.
Ohio Conservative Energy Forum	Ohio Conservative Energy Forum.
Ohio Consumers	Office of The Ohio Consumers' Counsel.
Omaha Public Power	The Omaha Public Power District.
OMS	The Organization of Midcontinent Independent System Operator States, Inc.
Onward Energy	Onward Energy Holdings, LLC.
Ørsted	Ørsted North America.
Pacific Northwest State Agencies	The Washington Utilities and Transportation Commission; Oregon Public Utility Commission; Washington State Department Of Commerce; and Oregon Department Of Energy.
Pacific Northwest Utilities	Avista Corporation; Portland General Electric; Puget Sound Energy, Inc.; and Tacoma Power.
PacifiCorp and NV Energy	PacifiCorp; Nevada Power Company and Sierra Pacific Power Company (together, NV Energy).
Pattern Energy	Pattern Energy Group LP.
Payton Alaama	Payton Alaama.
Pennsylvania Commission	The Pennsylvania Public Utility Commission.
PG&E	Pacific Gas and Electric Company.
Pine Gate	Pine Gate Renewables, LLC.
PIOs	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, jointly Public Interest Organizations.
PJM	PJM Interconnection, L.L.C.
PJM Market Monitor	The Independent Market Monitor of PJM Interconnection, L.L.C.
PJM States	The Organization of PJM States, Inc. (OPSI).
Policy Integrity	The Institute for Policy Integrity at New York University School of Law.
Potomac Economics	Potomac Economics, Ltd.
PPL	PPL Electric Utilities Corporation; Louisville Gas & Electric and Kentucky Utilities (collectively LG&E/KU); and The Narragansett Electric Company.
Prysmian	The Prysmian Group.
Public Systems	Massachusetts Municipal Wholesale Electric Company; New Hampshire Electric Cooperative, Inc.; Connecticut Municipal Electric Energy Cooperative; and Vermont Public Power Supply Authority.
QCo	QCoefficient, Inc.
R Street	R Street Institute.
Rail Electrification	The Rail Electrification Council.
Renewable Northwest	Renewable Northwest.
Resale Iowa	Resale Power Group of Iowa.
RMI	RMI.
SDG&E	San Diego Gas & Electric Company.
SEIA	The Solar Energy Industries Association.
SEPA	The Smart Electric Power Alliance.
SERTP Sponsors	Associated Electric Cooperative, Inc.; Dalton Utilities; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC; Georgia Transmission Corporation; Louisville Gas and Electric Company and Kentucky Utilities Company; the Municipal Electric Authority of Georgia; PowerSouth Energy Cooperative; Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company; the Tennessee Valley Authority; and Gulf Power Company, collectively Sponsors of the Southeastern Regional Transmission Planning Process (SERTP).
Shell	Shell Energy North America (U.S.), L.P.; Shell New Energies U.S., LLC; and Savion L.L.C.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Signatories	American Council on Renewable Energy; Americans for a Clean Energy Grid; American Clean Power Association; AES Corporation; Advance Energy Economy; Center for Rural Affairs; Clean Air Task Force; Clean Energy Buyers Alliance; Conservative Energy Network; ConEd Transmission, Inc.; Enel North America, Inc.; Exelon Corporation; GE Renewables; Grid United LLC; Google; Holy Cross Energy; Invenergy; ITC Holdings Corp.; Land & Liberty Coalition; Macro Grid Initiative; National Audubon Society; National Electrical Manufacturer Association; National Wildlife Federation; Natural Resources Defense Council; NextEra Energy, Inc.; Northwest & Intermountain Power Producers Coalition; Pattern Energy; Rail Electrification Council; Rocky Mountain Institute (RMI); Sierra Club; Solar Energy Industries of America; and Southern Renewable Energy Association.
Six Cities	The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
Smart Wires	Smart Wires.
SoCal Edison	Southern California Edison Company.
Southeast PIOs	Southern Environmental Law Center; Energy Alabama; North Carolina Sustainable Energy Association; South Carolina Coastal Conservation League; Southface Energy Institute; and Southern Alliance for Clean Energy, jointly Southeast Public Interest Groups.
Southern	Southern Company Services, Inc.
Southwestern Power Group	Southwestern Power Group.
SPP	Southwest Power Pool Inc.
SPP Market Monitor	The Southwest Power Pool Market Monitoring Unit.
SREA	Southern Renewable Energy Association.
State Agencies	Connecticut Department of Energy and Environmental Protection; Connecticut Attorney General; Connecticut Office of Consumer Counsel; Connecticut Public Utilities Regulatory Authority; California Energy Commission; Delaware Division of the Public Advocate; Attorney General of the District of Columbia; Maine Office of the Public Advocate; Maryland Attorney General; Massachusetts Attorney General; Michigan Attorney General; Pennsylvania Office of The Consumer Advocate; and the Rhode Island Attorney General.
State of Tennessee	State of Tennessee.
State Officials	Maine Governor's Energy Office; Washington State Department of Commerce; Arizona Governor's Office of Resiliency; California Natural Resources Agency; Colorado Energy Office; Deputy Governor of Illinois; Maryland Energy Administration; Michigan Department of Environment, Great Lakes, and Energy; New Mexico Energy Minerals and Natural Resources Department; Office of New York Governor Kathy Hochul; and Office of North Carolina Governor Roy Cooper.
State Water Contractors	State Water Contractors.
Tabors Caramanis Rudkevich	Tabors Caramanis & Rudkevich.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
Transmission Dependent Utilities	Golden Spread Electric Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc., collectively, Transmission Dependent Utility Systems.
Transource	Transource Energy, LLC.
Undersigned States [Initial Comments]	Utah Attorney General; Alaska Attorney General; Georgia Attorney General; Idaho Attorney General; Indiana Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; North Dakota Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina Attorney General; Texas Attorney General; West Virginia Attorney General; and Wyoming Attorney General.
Undersigned States [Reply Comments]	Utah Attorney General; Alabama Attorney General; Alaska Attorney General; Arkansas Attorney General; Florida Attorney General; Georgia Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina Attorney General; Texas Attorney General; and West Virginia Attorney General.
U.S. Chamber of Commerce	U.S. Chamber of Commerce.
U.S. Climate Alliance	United States Climate Alliance.
U.S. Democratic Representatives	U.S. Representatives Paul D. Tonko and 112 additional U.S. Representatives.
U.S. DOE	United States Department of Energy.
U.S. DOJ and FTC	United States Department of Justice and the Federal Trade Commission.
U.S. House Republicans	U.S. Representatives Andrew R. Garbarino; Anthony D'Espositio; Nicholas A. Langworthy; and Brandon Williams.
U.S. Senator Barrasso	U.S. Senator John Barrasso.
U.S. Senator Heinrich	U.S. Senator Martin Heinrich.
U.S. Senators	U.S. Senators Martin Heinrich; Edward J. Markey; Peter Welch; John Hickenlooper; Angus S. King, Jr.; Ron Wyden; Robert P. Casey, Jr.; Sheldon Whitehouse; Tina Smith; Ben Ray Luján; Chris Van Hollen; Mazie K. Hirono; Jeffrey A. Merkley; Brian Schatz; Thomas R. Carper; Bernard Sanders; Patty Murray; John Fetterman; Michael F. Bennet; Elizabeth Warren; and Alex Padilla.
U.S. Senators Heinrich and Lee	U.S. Senators Martin Heinrich and Mike Lee.
U.S. Senators Hickenlooper and King	U.S. Senators John Hickenlooper and Angus S. King, Jr.
U.S. Senator Schumer	U.S. Senator Charles E. Schumer.
U.S. Senator Whitehouse	U.S. Senator Sheldon Whitehouse.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Utah Commission	The Utah Public Service Commission.
Utah Division of Public Utilities	Utah Department of Commerce, Division of Public Utilities.
VEIR	VEIR Inc.
Vermont Electric and Vermont Transco	Vermont Electric Power Company, Inc., and Vermont Transco LLC.
Vermont State Entities	The Vermont Public Utility Commission and the Vermont Department of Public Service.
Virginia Attorney General	Virginia Office of the Attorney General, Division of Consumer Counsel.
Virginia Commission Staff	The Staff of the Virginia State Corporation Commission.
Vistra	Vistra Corp.
WATT Coalition	The Working for Advanced Transmission Technologies (WATT) Coalition.
WE ACT	WE ACT for Environmental Justice.
West Virginia Commission	The Public Service Commission of West Virginia.
Western PIOs	Center for Energy Efficiency and Renewable Technologies; NW Energy Coalition; Western Resource Advocates; and Renewable Northwest; collectively, Western Public Interest Organizations.
Western State Representatives	Agency Representatives from the states of Arizona; California; Idaho; Montana; Nevada; Oregon; South Dakota; Utah; Washington; and Wyoming.
Western Way Colorado	Western Way Colorado.
Western Way Nevada	Western Way Nevada.
Western Way Utah	Western Way Utah.
Wildlife Federation Action Fund Supporters	8,610 Supporters of the National Wildlife Federation Action Fund.
WIRES	WIRES.
Wisconsin Conservative Energy Forum	Wisconsin Conservative Energy Forum.
Wisconsin Legislators	Wisconsin State Senator Julian Bradley and Wisconsin State Representative David Steffen.
Wisconsin Senator Cowles	Wisconsin State Senator Robert L. Cowles.
Xcel	Xcel Energy Services Inc.

Appendix B: Pro Forma Open Access Transmission Tariff Attachment K

Note: Proposed deletions are in brackets and proposed additions are in italics.

Attachment K

Transmission Planning Process

Local Transmission Planning

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

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No*s.* 1000 *and 1920.* The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

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

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

The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region. The three *meetings must occur before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's transmission planning models. The three stakeholder meetings for local transmission planning information are the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, and the three stakeholder meetings must meet the requirements in Order No. 1920.*

As part of the regional transmission planning process, the Transmission Providers in each transmission planning region shall conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. As part of this Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall meet the requirements set forth in Order No. 1920, including: (1) identifying Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. 1920; (2) measuring the required seven benefits consistent with the requirements set forth in Order No. 1920; (3) using the measured benefits to evaluate Long-Term Regional Transmission Facilities; and (4) using selection criteria consistent with the requirements set forth in Order No. 1920 that provide the opportunity for Transmission Providers to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address Long-Term Transmission Needs.

The process through which the Transmission Providers in each transmission planning region develop Long-Term Scenarios must comply with the following six transmission planning principles established in Order No. 890: coordination; openness; transparency; information exchange; comparability; and dispute resolution. The Transmission Providers in each transmission planning region shall outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios. The Transmission Providers in each transmission planning region shall also outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios.

The Transmission Providers in each transmission planning region shall include in their Tariffs a general description of how they will measure each of the seven required benefits used to evaluate Long-Term Regional Transmission Facilities. The Transmission Providers in each transmission planning region shall measure and use the seven benefits, as described in Order No. 1920, in Long-Term Regional Transmission Planning.

As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall include in their Tariffs an evaluation process, including selection criteria, that: (1) is transparent and not unduly discriminatory; (2) aims to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; (3) seeks to maximize benefits accounting for costs over time without over-building transmission facilities; and (4) otherwise satisfies the requirements set forth in Order No. 1920.

The Transmission Providers in each transmission planning region shall include in their Tariffs one or more Long-Term Regional Transmission Cost Allocation Methods, which is an ex ante regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation and that complies with the requirements set forth in Order No. 1920. The Transmission Providers in each transmission planning region may also, subject to (1) the agreement of Relevant State Entities and (2) Commission acceptance, include in their Tariffs a State Agreement Process. A State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. The Tariff must describe how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the transmission provider; and the circumstances under which, or the information necessary for, a transmission provider to file or to consider filing the agreed cost allocation.

As part of evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities, the Transmission Providers in each transmission planning region shall consider in all of their regional transmission planning and cost allocation processes whether selecting transmission facilities that incorporate the following technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies: dynamic line ratings, as defined in 18 CFR 35.28(b)(14), advanced power flow control devices, advanced conductors, and/or transmission switching. Specifically, such consideration must include both: (1) whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching as part of any potential regional transmission facility would be more efficient or cost-effective. Transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of Order No. 1920.

The Transmission Providers in each transmission planning region shall evaluate for potential selection in the regional transmission plan for purposes of cost allocation regional transmission facilities that address interconnection-related transmission needs originally identified through the generator interconnection process. This requirement applies in the existing Order No. 1000 regional transmission planning processes. The Transmission Providers must modify their Tariffs to include these requirements. The interconnection-related transmission needs that Transmission Providers must evaluate in the existing Order No. 1000 regional transmission planning process are those for which:

(1) Transmission Providers in the transmission planning region have identified the relevant interconnection-related transmission need in interconnection studies in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the accepted tariff provisions proposed to comply with this reform in Order No. 1920, and the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions);

(2) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need has a voltage of at least 200 kV and an estimated cost of at least $30 million;

(3) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need is not currently planned to be developed because the interconnection request(s) that led to the identification of the interconnection-related transmission need has been withdrawn; and

(4) the Transmission Providers have not identified a different interconnection-related Network Upgrade to meet the relevant interconnection-related transmission need in an executed Generator Interconnection

Agreement or in a Generator Interconnection Agreement that the interconnection customer requested that the Transmission Provider file unexecuted with the Commission.

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

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the *regional* transmission planning process and seek regional cost allocation;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the *regional* transmission planning process;

(ix) The dispute resolution process;

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

[The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order Nos. 1000; and]

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include [a]cost allocation method*s* [or methods]that satisfy the [six regional cost allocation principles]*requirements* set forth in Order No*s*. 1000 *and 1920.*

Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above a voltage threshold not to exceed 200 kV that an individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be ''right-sized'' to more efficiently or cost-effectively address Long-Term Transmission Needs, as discussed in Order No. 1920. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. 1920. The Transmission Providers in each transmission planning region shall include in their Tariffs a cost allocation method for right-sized replacement transmission facilities that are selected in the regional transmission plan for purposes of cost allocation.

Interregional Transmission Coordination

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

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

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

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions, *including those that may be more efficient or cost-effective transmission solutions to Long-Term Transmission Needs;*

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or email list for the communication of information related to the coordinated planning process, *including:*

(a) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings;

(b) any interregional transmission facilities proposed or identified in response to the Long-Term Transmission Needs;

(c) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning;

(d) the results of any cost-benefit evaluation of such interregional transmission facilities, with results including both any overall benefits identified, as well as any benefits particular to each transmission planning region; and

(e) the interregional transmission facilities, if any, selected in the regional transmission plan for purposes of cost allocation to meet Long-Term Transmission Needs.

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

United States of America—Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

Docket No. RM21–17–000

(Issued May 13, 2024)

PHILLIPS, Chairman, CLEMENTS, Commissioner, *concurring:*

1. The electric transmission grid is the backbone of the American economy and essential to the national security of our country. The mission of this agency is to ensure reliable, safe, secure, and economically efficient energy for consumers at a reasonable cost. Ensuring we have a robust, well-planned electric transmission grid is the single most important step that this Commission can take to fulfill that statutory mandate. It is a *reliability imperative.* The transmission grid ultimately allows consumers to have access to the electricity they need—when they need it—to power their homes and businesses. It is equally an *affordability imperative.* The transmission grid gives those same consumers access to diverse, low-cost sources of electricity that help ensure energy bills remain just and reasonable. All told, a strong electric transmission grid is the foundation for how this Commission meets its most important statutory responsibilities under the Federal Power Act (FPA).

2. That has never been more true than it is today. We are in the midst of a pivotal moment for the electricity system. As a nation, we are seeing unprecedented demands on the grid from extreme weather, increasing and rapidly changing patterns of electricity use, and fundamental shifts in the resource mix. And there is every reason to believe those trends will continue, and, indeed, accelerate, in the years ahead.

3. At the same time, our transmission grid is old. More than 70 percent of the grid was built over 25 years ago and much of it was put into service in the 1960s and 1970s, when this agency was still the Federal Power Commission. Our country cannot meet the challenges of today, let alone tomorrow, with yesterday's transmission system. And being unprepared to meet those increased demands jeopardizes the safety and security of our grid. Nevertheless, as a country, we have so far failed to make the investments in the types of transmission facilities needed to ensure continued reliability and affordability at anywhere near the scale or speed needed to meet this pivotal moment.

4. The cost of continued inaction is immeasurable. Failure to act now would hamper the reliability and resilience of our electric grid while leaving customers holding the bag for the inevitably more costly upgrades in the future. Indeed, under the

status quo, with its de facto emphasis on the piecemeal, just-in-time development of the grid to meet near-term reliability and economic needs, customers are being forced to fund investments that could have been more beneficial, less costly, or both had they been better planned from the start. That result undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country.

5. Avoiding those costs requires a forward-looking, comprehensive, and holistic transmission planning and cost allocation framework. That framework must consider the diverse challenges facing the transmission grid, identify the solutions that will address those challenges, and ensure only customers who benefit from those facilities pay their share of the cost, while ensuring that customers who do not benefit do not pay. Period.

6. We must conduct this planning and cost allocation on a regional basis and with an aperture consistent with the scope and scale of the challenges we face. That is, after all, why Congress enacted Title II of the FPA: To provide a coherent regional and national regulatory regime and avoid the harms and costs that come from a balkanized electricity system in which every state is its own regulatory island.[1]

7. Today's final rule does just that. We are requiring transmission planners to plan Long-Term Regional Transmission Facilities using the factors we know drive the transmission needs of tomorrow and consider the reliability and affordability benefits those facilities will provide. At the same time, we are giving transmission planners discretion regarding whether and how to select which transmission facilities to build, recognizing no two regions of the country are alike and a one-size-fits-all solution simply will not produce the infrastructure we so badly need.

8. When it comes to the critical question of ''who pays,'' we are providing transmission planners with the maximum flexibility we can legally allow in order to facilitate negotiated, regionally appropriate solutions. And, as part of a multi-pronged approach to protecting customers, we are requiring transmission planners to reevaluate any previously selected Long-Term Regional Transmission Facility when the actual or projected costs of that facility significantly exceed the cost estimates used during selection. Finally, we are also providing states with unprecedented, expanded opportunities to work with transmission providers to shape the cost allocation approaches of their regions, while meeting the beneficiary pays requirement that is the foundation of cost causation under the FPA's just and reasonable standard.

[1] *New York* v. *FERC,* 535 U.S. 1, 6 (2002) (''When it enacted the FPA in 1935, Congress authorized federal regulation of electricity in areas beyond the reach of state power,'' tasking the Commission's predecessor with ''effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce.'' (quoting *Gulf States Utils. Co.* v. *F.P.C.,* 411 U.S. 747, 758 (1973))); *FERC* v. *Elec. Power Supply Ass'n,* 577 U.S. 260, 265–66 (2016) (*EPSA*) (same); *cf. First Iowa Hydro-Elec. Co-op* v. *F.P.C.,* 328 U.S. 152, 180 (1946) (The Federal Water Power Act of 1920 was ''a complete scheme of national regulation which would promote the comprehensive development of the water resources of the Nation, in so far as it was within the reach of the federal power to do so, instead of the piecemeal, restrictive, negative approach of the River and Harbor Acts and other federal laws previously enacted.'').

I. The Dissent's Approach Would Not Result in the Energy Infrastructure Buildout We Need

9. Commissioner Christie provides a stark alternative vision in his dissent, one that would violate the cost causation principle and harm electric reliability. While we agree with his emphasis on the importance of cooperation with states—and have created unprecedented opportunities for such cooperation throughout this final rule—his radical new approach would permit a state to receive economic, resilience, and reliability benefits from new energy infrastructure, but not be charged a single cent unless they expressly agree to pay. That myopic view does not satisfy the requirements of the FPA and would not adequately facilitate the development of transmission we desperately need to ensure reliability and affordability. Contrary to the dissent's assertion that this final rule is the product of a political agenda, failing to act based on the dissent's flawed reading of the circumstances through the lens of politics would abdicate the Commission's duty.

10. The dissent's approach would necessarily require the Commission to ignore evidence about which consumers benefit from the increased reliability, resilience, and affordability due to grid expansion. Instead, backbone regional transmission could not be built unless every state unanimously opted into an agreed cost allocation. But for the same reason that passing around a hat is no way to fund the fire department, roads, or bridges, such an approach to building critical, public interest infrastructure that relies entirely on the voluntary contributions of individual states (or could even be defeated by the refusal to contribute by a single state) will not beget the transmission infrastructure needed to maintain reliability and affordability.

11. Put another way, there is little reason to believe that we, as a country, would build the infrastructure needed to power the world's largest economy if individual states that benefit from that infrastructure could simply decline to pay. Instead, Commissioner Christie's approach would be far more likely to result in a failure to make needed investments entirely, or else to down-size those investments in a way that results in exactly the type of piecemeal transmission development that led us to conclude existing transmission planning practices are rendering transmission rates unjust and unreasonable. That result would leave America far worse off. Just as the Articles of Confederation were not a sufficient platform to develop and sustain a national economy, so too would a wholly voluntary approach to paying for the needed infrastructure be inadequate to develop a transmission grid capable of powering the world's largest economy. That alone is a reason to reject Commissioner Christie's dissenting views.

12. In addition, the dissent's approach would result in subpar transmission planning. Our nation needs transmission planning that looks ahead on the decades-long timeframe that is relevant to building backbone transmission facilities that will likely last a half-century or more. And transmission needs can best be predicted by considering many factors to discern their aggregate effect. Those include economics and technology fundamentals, changing demand patterns across customers of all types (including corporations), the full panoply of federal, Tribal, state, and local policy contributions, and even the changing weather patterns, which pose increasing challenges to maintaining a reliable and resilient electric grid. Rather than reflect that integrated reality, Commissioner Christie's approach asks planners to isolate select state public policies and focus on how each individually shapes the grid. That too is a recipe for down-sizing needed infrastructure in a way that will result in less efficient or cost-effective investments that fail to meet this critical moment.

II. The Dissent Misrepresents the Final Rule

13. Commissioner Christie's dissent responds to a strawman of his own making, not the final rule. And, even so, the dissent's critique of the final rule ultimately boils down to one principal issue: the failure of the rule (in his view) to give every state an absolute right to veto the costs of a transmission facility, even one from which the state's consumers would derive economic and reliability benefits. Although we respect his perspective, we disagree that the changes he seeks are legal—much less legally required—or that a final rule premised on his vision would beget the energy infrastructure needed to maintain reliability and affordability. In any case, his statement mischaracterizes critical aspects of the final rule, the most fundamental of which we address below.

14. First and foremost, Commissioner Christie asserts that Long-Term Regional Transmission Facilities are public policy projects whose purpose is to facilitate state efforts to shape the resource mix. He is wrong. This final rule requires transmission providers to comprehensively consider the factors that will shape the transmission needs of tomorrow. Although state efforts to shape the resource mix are one of many factors transmission planners are required to consider under this final rule, Commissioner Christie's narrow focus on them misses the forest for a couple trees. The requirement to consider state public policies is part of the much broader requirement to comprehensively consider *all* significant factors shaping future transmission needs, where other factors, including the fundamental economic and reliability drivers, play a much bigger role. That Commissioner Christie is focused overwhelmingly on the state public policies with which he disagrees does not mean that the same is true of Long-Term Regional Transmission Facilities.

15. In any case, Commissioner Christie's proposal is arbitrary and capricious in its lack of any limiting principle. Transmission

needs of all sorts—economic or reliability, near-term or long-term—are shaped by all manner of state public policy choices. Fundamental state decisions, such as tax rates, zoning and land use laws, and almost every use of the police power more generally, inevitably shape the supply and demand of electricity. No transmission need is unaffected by those basic exercises of state power, which means that no transmission need can be fairly or accurately described as entirely divorced from the effects or consequences of state policy decisions.

16. While taking issue with some state policy choices, Commissioner Christie's vision contains no method for determining which state policies must be considered and which might escape scrutiny even though they too contribute to underlying transmission needs. Similarly, it contains no rubric for determining how to evaluate the cumulative effects of state public policies—such as taxation and land use laws—that are, in many cases, far in excess of those derived from the public policies on which he chooses to focus. Nor does it contain any explanation for subjecting Long-Term Regional Transmission Facilities to this suite of planning and cost allocation requirements, but not economic and reliability projects—which are, for the reasons noted above, inevitably at least in part the product of public policies. That sort of unexplained, arbitrary line drawing is exactly what the APA prohibits.[2]

17. Let us be clear: These are reliability and affordability projects. As the final rule explains, the minimum standards we establish provide that Long-Term Regional Transmission Facilities are to be identified and evaluated based on their reliability and economic benefits. To call them anything else—no matter how many times—is a misnomer, plain and simple.

18. Similarly, Commissioner Christie's claim that states will be forced to subsidize other states' public policy choices could not be further from the truth. A bedrock requirement of this final rule is that customers will only be required to pay for a share of a Long-Term Regional Transmission Facility to the extent they benefit from that facility. That is cost causation 101. While we provide transmission planners, in cooperation with their state regulators, ample flexibility to determine how to satisfy that bedrock requirement, any cost allocation methodology that causes customers to pay for projects from which they do not benefit—or to pay a cost share out of proportion to the benefits they draw from the project—would be patently unjust and unreasonable. That is black letter law under the FPA,[3] which we have expressly incorporated into the requirements of this final rule.[4]

19. The dissent is equally wrong to suggest that anything less than a unilateral right to veto cost responsibility for a regional transmission project is unfair to states. To the contrary, both courts and the Commission have long recognized that the just and reasonable standard of the FPA requires that customers pay for infrastructure they use and benefit from.[5] The dissent's approach, by contrast, would permit free ridership, allowing states to avoid paying by withholding their approval, while still receiving the substantial benefits of a more integrated, robust transmission system. Here too, both the Commission and the courts have expressly rejected that approach as inconsistent with cost causation.[6] Rather than ensure fairness, the dissent's approach would create perverse incentives, rewarding states that decline to pay for infrastructure development that demonstrably provides reliability and economic benefits to those states, while penalizing those who roll up their sleeves to get those projects built. That is a recipe for inaction, not for building the energy infrastructure we so badly need to maintain reliability and affordability.

20. We agree with Commissioner Christie that transmission development works best when states are key partners in the process. That is why we take the unprecedented steps described in the final rule to give them a central role. But partnership and collaboration are not the same thing as giving every state the right to veto cost responsibility for transmission projects thus allowing their residents to reap a windfall by benefitting from transmission facilities for which they did not pay their legally required share.

21. Commissioner Christie also asserts that the final rule deprives states of their long-standing authority. That is categorically false. Let us again be clear: States retain all the same authorities over retail rates and transmission siting they held prior to the final rule. Rather than deprive states of authority, the final rule *empowers* them with unprecedented opportunities to engage with transmission providers in developing a cost allocation framework.

22. Commissioner Christie's objection is to the structure of the FPA, and long-established, court-upheld Commission regulation of regional transmission planning under Order No. 1000, not the final rule. He objects to the transmission provider's role in deciding, without state approval, whether to invest in a transmission project and determine, subject to Commission oversight, which consumers must pay for it. But that basic structure is not new to the final rule—it is how transmission planning occurs today, consistent with the FPA and Commission precedent, including Order No. 1000. At Congress's direction, public utilities, not states, have the right to propose to the Commission rates and practices affecting those rates and we cannot deprive them of those rights.[7] Neither states' siting authority nor their exclusive jurisdiction over retail rates give them the unilateral right to dictate matters subject to the Commission's exclusive jurisdiction, such as the transmission rates and practices affecting those rates that are the subject of this final rule.[8] For example, a state could reject siting

[2] *See, e.g., Prometheus Radio Project* v. *F.C.C.,* 373 F.3d 372, 390 (3rd. Cir. 2004) (explaining that when an agency has engaged in line-drawing, ''its decisions may not be 'patently unreasonable' or run counter to the evidence before the agency'' (citations omitted)); *Sinclair Broadcast Grp., Inc.* v. *F.C.C.,* 284 F.3d 148, 162 (D.C. Cir. 2002) (explaining that lines drawn cannot be ''patently unreasonable, having no relationship to the underlying regulatory problem'' (citing *Cassell* v. *F.C.C.,* 154 F.3d 478, 485 (D.C. Cir. 1998)); *Am. Trucking Assocs., Inc.* v. *I.C.C.,* 697 F.2d 1146, 1151 (D.C. Cir. 1983) (''The arbitrariness which the [Administrative Procedure Act] proscribes is the failure to draw reasoned distinctions where reasoned distinctions are required.'').

[3] *See City of Lincoln* v. *FERC,* 89 F.4th 926, 930 (D.C. Cir. 2024) (''The FPA's just and reasonable standard incorporates a cost-causation principle.''); *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d 1254, 1255 (D.C. Cir. 2018) (''Under the [FPA], electric utilities must charge just and reasonable rates. For decades, the Commission and the courts have understood this requirement to incorporate a cost-causation principle—the rates charged for electricity should reflect the costs of providing it.'' (citations omitted)); *see also BNP Paribas Energy Trading GP* v. *FERC,* 743 F.3d 264, 268 (D.C. Cir. 2014) (''[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.'').

[4] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Order No. 1920, 187 FERC ¶ 61,068, at P 1305 & n.2786 (2024).

[5] Beneficiary pays is founded on a recognition, grounded in the unbreakable laws of physics, that ''the nature of power flows over an interconnected transmission system does not permit a public utility transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them.'' Order No. 1000, 136 FERC ¶ 61,051 at P 534; *see also id* P 535 (''the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them''); *Ill. Commerce Comm'n* v. *FERC,* 576 F.3d 470, 476–77 (7th Cir. 2009) (*ICC* v. *FERC I*) (''All approved rates must reflect to some degree the costs actually caused by the customer who must pay them . . . To the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.'' (internal citations omitted)); *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) (''FERC and the courts have added flesh to these bare statutory bones, establishing what has become known in Commission parlance as the 'cost-causation' principle. Simply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.''); *see, e.g., Sw. Power Pool,* 182 FERC ¶ 61,141, at PP 12, 99–103 (2023).

[6] Order No. 890, 118 FERC ¶ 61,119 at P 561 (''there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it''); Order No. 1000, 136 FERC ¶ 61,051 at P 535 (''[if] the Commission could not address free rider problems associated with new transmission investment, [ ] it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory''); *El Paso Elec. Co.* v. *FERC,* 76 F.4th 352, 363 (5th Cir. 2023) (''No amount of emphasizing other competing interests permits FERC to sacrifice the foundational principle of cost-causation by refusing to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits.'' (citations omitted)).

[7] 16 U.S.C. 824d; *Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002) (''Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets.'').

[8] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 253–83 (affirming Commission's legal authority to

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or other approvals for the portion of a regional transmission project located within its jurisdiction, provided that its determination was consistent with relevant state and federal law. But states cannot stymie needed regional transmission projects by simply declining to pay for them. Nor is that concept new to this final rule. Under established economic and reliability planning, state policies are contributing factors to needed transmission, and states have never held a veto authority over costs for such facilities under Order No. 1000.[9] Nothing in this final rule changes those basic facts.

23. What has changed is that states now, *as a result of this final rule,* have an unprecedented opportunity to shape transmission planning and cost allocation, elevating our system of cooperative federalism with the states to a degree not previously seen in the history of this Commission. Most significantly, we are requiring transmission providers to host a dedicated forum for meaningful state participation in proposing cost allocation methods and processes. And the rule also permits a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Transmission Facilities. Beyond cost allocation, states will have an opportunity to provide input on how to account for specific factors in Long-Term Scenarios, and states can provide information on how their own policies and planning affect Long-Term Transmission Needs. The rule also requires transmission providers to consult with and seek the support of states regarding how Long-Term Regional Transmission Facilities are evaluated and selected. We expect that where states come together to articulate workable, legal frameworks for planning and paying for needed infrastructure, their transmission providers will listen.

24. Indeed, under the State Agreement Process provided in the final rule, states very well could agree to, and transmission planners could adopt, a version of Commissioner Christie's preferred cost allocation approach.[10] So long as those expected to use the Long-Term Regional Transmission Facilities pay a share of the cost that is roughly commensurate with the benefits they will receive, nothing in this final rule prohibits states in a transmission planning region from adopting Commissioner Christie's preferred approach for funding the transmission facilities they need to ensure reliability and affordability.

25. Commissioner Christie also asserts that this final rule breaks with Order No. 1000 by mandating outcomes rather than regulating transmission planning processes. Here, too, he is wrong. The rule is clear that no transmission provider is required to select any particular project.[11] Instead, just as in Order No. 1000, the obligation on the transmission provider is to plan for the world as we expect it to be and then make its own business decisions after having conducted that planning process. The final rule's minimum planning standards do not un-do that core discretion. Requiring planning to be based upon documented drivers of transmission needs and to incorporate objective measures of how potential investments pay off improves the planning *process,* it does not mandate any particular outcome.[12] In short, in recasting the rule to fit his narrative, Commissioner Christie conveniently ignores one of its core elements: that it imposes no obligation to develop any regional transmission project.

26. Finally, Commissioner Christie is also incorrect in arguing that this final rule violates the Major Questions Doctrine. He asserts two bases for that argument, neither of which hold water.

27. First, he contends that our *intention* in issuing this final rule is to elicit trillions in spending on transmission. As an initial matter, the goal of this final rule is to facilitate the development of transmission infrastructure *needed* to maintain reliability and affordability. That is the case no matter how many times or in how many ways Commissioner Christie purports to ascribe our 'true' intentions. In any case, his trillion-dollar estimates are nothing more than a sleight of hand that is unsupported by the record before us. To support his claim that this final rule will cause ''literally trillions'' in transmission investment, he cites to one academic study and one news article stating that in order to achieve a ''net-zero'' emissions level by 2050, trillions will need to be spent on transmission.[13] Putting aside whether that figure is accurate and whether ''net zero'' is an appropriate policy goal for the country—a question which we agree is not for this Commission to resolve—it is an astounding logical leap to say that because certain individuals believe a certain amount of investment is necessary to achieve a certain policy goal, that this rule will necessary cause customers to spend that amount of money. In any case, as the dissent points out, significant investments in transmission are already being made by public utilities around the country regardless of anything we do—or do not do—here today. This final rule regulates the process by which those investments are identified, evaluated and, where appropriate, selected in order to help ensure that they reflect the most efficient and cost-effective options available. That is what the Commission has been doing for decades; the fact that transmission has become a more politically salient topic does not transform our longstanding practice into a major question.

28. Second, he contends that our statement that the Commission has exclusive jurisdiction over the transmission planning practices that directly affect wholesale rates means that this Commission has crossed the major questions Rubicon. But it was the courts, not this Commission, that took that step. As he observes in his dissent, *South Carolina* concluded that the transmission planning practices regulated by Order No. 1000—which are the same practices addressed by this final rule—were practices that directly affected wholesale rates and thus fall squarely within the Commission's jurisdiction.[14] And as the courts have explained, where a practice meets that directly affecting standard, it falls within the Commission's exclusive jurisdiction.[15] This long-settled law in no way alters or dilutes the significant and critical role for states to play under their jurisdiction and, as noted above, we have significantly expanded that role in this final rule. Rather it means that the specific practices in the tariffs on file with this Commission, as required by this final rule, are within the Commission's exclusive jurisdiction, not that of the states. The final rule's recitation of black letter law hardly runs afoul of the major questions doctrine.

III. We Encourage Transmission Providers To Facilitate Joint Ownership Structures

29. Finally, we would be remiss not to mention one policy priority that is not finalized in this rule: The creation of a federal right of first refusal for certain transmission facilities developed through a joint ownership structure. As the final rule explains, we find that proposal is better considered as part of our generic proceeding on Transmission Planning and Cost Management, where it can be evaluated

require participation in Long-Term Regional Transmission Planning).

[9] Indeed, Commissioner Christie recently approved, over the objection of other states, PJM's plan to regionally allocate the costs of transmission to address reliability concerns driven, at least in part, by Virginia's policy to incent siting of data centers in that state. *See PJM Interconnection, L.L.C.,* 187 FERC ¶ 61,012 (2024).

[10] We find Commissioner Christie's contention that the final rule would end PJM's use of its existing State Agreement Approach, and MISO and SPP's respective regional state committees, puzzling. Order No. 1920, 187 FERC ¶ 61,068 (2024) (Christie, Comm'r, dissenting, at P 11). The final rule enhances states' role and relaxes certain Order No. 1000 requirements for state-approved cost allocations. It is inexplicable that these additional flexibilities would result in transmission providers rolling back opportunities for state engagement in existing Order No. 1000 processes, where that is the opposite of the thrust of the final rule. Moreover, PJM's State Agreement Approach was approved outside of compliance with Order No. 1000 and has never served as PJM's exclusive *ex ante* cost allocation method, as Commissioner Christie suggests.

[11] Order No. 1920, 187 FERC ¶ 61,068 at P 1026 (''The Commission did not propose in the NOPR, and we will not require in this final rule, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.'').

[12] *Id.* (''In other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.'').

[13] *Id.* (Christie, Comm'r, dissenting at P 3 & n.7.

[14] In *South Carolina,* it was undisputed that transmission planning generally was a practice that directly affected wholesale rates, but the court further held that the absence of regional transmission planning was itself such a practice. *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41, 56–59 (D.C. Cir. 2014).

[15] *See, e.g., Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 964 F.3d 1177, 1181 (D.C. Cir. 2020) (''Congress g[ave] the Federal Energy Regulatory Commission . . . exclusive authority over the regulation of the sale of electric energy at wholesale in interstate commerce, including both wholesale electricity rates and any rule or practice affecting such rates.'' (cleaned up)).

alongside other proposals for ensuring that transmission facilities are developed as efficiently and cost-effectively as possible.[16]

30. Nevertheless, we underscore that our decision today should not be construed as a lack of support for the concept of joint ownership or the potential for a federal ROFR to effectively encourage its use. Indeed, joint ownership structures that partner transmission owners with other load-serving entities in their footprint, such as public power or non-profit cooperatives, can provide many benefits and should be encouraged.

31. In these arrangements, the load-serving entity partner's participation can reduce costs for customers in the footprint. Such joint ownership structures bring together diverse parties, allowing the participating entities to better allocate risks and responsibilities, capture efficiencies, and promote innovation, all to customers' ultimate benefit.[17] Moreover, by bringing a wider range of entities into the transmission development fold, joint ownership can leverage additional sources of capital, including those that do not typically invest in transmission facilities, which can itself have significant benefits for customers.[18]

32. For example, TAPS highlights specific instances of joint ownership arrangements with tax-exempt public power entities providing significant savings to customers.[19] TAPS and APPA estimate these kinds of joint ownership arrangements can typically yield a ''more than a 5% annual cost reduction in ratepayer-funded return and associated tax costs,'' which could produce billions of dollars in savings when applied to reasonable transmission investment forecasts.[20] Relatedly, NRECA highlights examples of joint ownership arrangements with electric cooperatives yielding reliability and efficiency benefits, including, among others, leveraging electric cooperative's ability to provide increased operations and maintenance support and access to lower cost financing through the Rural Utilities Service.[21]

33. In light of those substantial benefits, we clarify that nothing in this final rule should be interpreted to prohibit or impair joint ownership arrangements. To the contrary, we encourage transmission providers, in compliance with this rule and elsewhere, to find ways to encourage these arrangements. For example, in compliance with this rule, transmission planners could use joint ownership as a factor to be considered in evaluating and selecting the more efficient or cost-effective solution to meet a long-term transmission need. Similarly, we note that the developers of a jointly owned transmission facility can consider seeking transmission incentives under section 205 of the FPA that reflect the risks and challenges associated with developing such facilities.[22] In addition, the Commission will continue to evaluate other potential actions to incentivize joint ownership, including considering in the Commission's cost management proceeding whether to provide a right of first refusal or other mechanisms to encourage its use.

* * * * *

34. Our electric transmission grid is at a crossroads. Our nation is facing down an extended period of unprecedented change in demand, supply, and the myriad other factors that fundamentally shape our energy needs. And we do so with a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality.

35. We have a choice: We can take consequential action to build the infrastructure needed to ensure reliability and affordability. Or we can pursue half-measures, which may help on the margins, but will ultimately leave us lacking the infrastructure we need to keep the lights on at a price that customers can afford. With this final rule, we emphatically choose the former path.

36. But we are not going down this road alone. As discussed above, we have opened the door for our state partners to play a leading role in shaping the next generation of energy infrastructure. We urge them to walk through it and deploy their unique perspectives as regulators and siting authorities of electric infrastructure to develop regionally tailored solutions. Together, we can forge a process that will serve customers for generations to come. This is the moment to step up, to develop both processes and physical infrastructure to withstand the changes and challenges ahead. This is the moment to build an electric transmission grid for the 21st century.

For these reasons, we respectfully concur.

Willie L. Phillips
Chairman

Allison Clements
Commissioner

United States of America—Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

Docket No. RM21–17–000

(Issued May 13, 2024)

CHRISTIE, Commissioner, *dissenting:*

I. The Final Rule Is a Pretext for Enacting a Sweeping Policy Agenda Never Passed by Congress, Denies the States the Authority Promised by the NOPR, and Fails the Commission's Consumer Protection Duty Under the Federal Power Act

1. The Federal Power Act (FPA) is, at its core, a consumer protection statute.[1] In FPA section 206, which today's final rule purports to be based on, Congress explicitly directed this Commission to protect consumers from public utility ''rates'' that are ''unjust, unreasonable, unduly discriminatory or preferential.'' [2] This final rule, however, fails

[16] Order No. 1920, 187 FERC ¶ 61,068 at PP 1563–64 & n.3346.

[17] *See, e.g.,* TAPS Initial Comments at 33–34 (''As explained in the TAPS 2021 White Paper, inclusive joint transmission ownership arrangements—whether structured as an inclusive transco, a shared system, or joint ownership of new transmission facilities—result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the needs of all LSEs.'' (citing TAPS, *Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Site and Build Transmission Need to Support Our Changing Resource Mix* (June 2021), *https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf*)); *see also* Rob Gramlich et al., Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission,* at 11–30 (Feb. 2024) (attached to WIRES Supplemental Comments) (highlighting specific examples of large regional transmission projects that resulted from diverse partnerships, including with public power entities and cooperatives, and which met many transmission needs and produced a wide range of benefits).

[18] *See, e.g.,* APPA Initial Comments, attach. at 4–10 (Declaration of James Pardikes) (listing advantages in equity ratio, debt cost, and income tax expense, and opportunities for risk diversification as potential benefits of joint ownership arrangements with public power utilities); NRECA Reply Comments at 15–16; Citizens Energy Reply Comments at 2–4 (describing how its unique joint ownership business model enables Citizens to provide direct support to low-income ratepayers and disadvantaged communities, addresses multiple concerns that arise in transmission development, and advances multiple Commission policy goals).

[19] TAPS Initial Comments at 45 (examining savings across Vermont Transco, ATCLLC, Fargo Project, and SE Missouri Project).

[20] TAPS Initial Comments at 45–46 & nn.133–135; APPA Reply Comments at 4.

[21] GDS Assocs., *National Rural Electric Cooperative Association,* at 25–27 (Aug. 17, 2021) (attached to NRECA Initial Comments).

[22] *See Promoting Transmission Investment Through Pricing Reform,* 141 FERC ¶ 61,129, at P 24 (2012) (''The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks.''); *Promoting Transmission Investment Through Pricing Reform,* Order No. 679, 116 FERC 61,057, at P 354 (2006) (''[T]o the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project. Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.'').

[1] *E.g., Towns of Alexandria, Minn.* v. *FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977) (explaining that the FPA's '' 'primary aim is the protection of consumers from excessive rates and charges' '') (quoting *Mun. Light Bds.* v. *FPC,* 450 F.2d 1341, 1348 (D.C. Cir. 1971)); *see also Elec. Dist. No. 1* v. *FERC,* 774 F.2d 490, 492 (D.C. Cir. 1985) (recognizing that the benefits of rate predictability, which are the ''whole purpose'' of the filed rate doctrine, ought to be considered in light of the FPA's ''primary purpose of protecting the utility's customers'').

[2] 16 U.S.C. 824e. Under the FPA, the Commission is a regulator of wholesale public utility *rates,* not a national integrated resource planner (known in the lingo as an ''IRP'') of generation and/or transmission. *See, e.g., Entergy Nuclear Vt. Yankee, LLC* v. *Shumlin,* 733 F.3d 393, 417 (2d Cir. 2013) (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.,* 71 FERC ¶ 61,269, at 62,080 (1995) (''[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable

Continued

to fulfill the Commission's consumer protection duty required by the statute. The final rule should be seen for what it is: a pretext to enact, through administrative action, a sweeping legislative and policy agenda that Congress never passed.[3] The final rule claims statutory authority the Commission does not have to issue an absurdly complex bureaucratic blizzard of mandates and micromanagement[4] to be imposed on every transmission provider in the United States for the transparent goal of spending trillions of consumers' dollars on transmission *not* to serve consumers in accordance with the FPA, but instead to serve political, corporate, and other special-interest agendas that were never enacted into law.[5] The rates for transmission that will result from the final rule will not only be unjust, unreasonable, unduly discriminatory and preferential, but grossly unfair to tens of millions of American consumers already burdened with rapidly growing monthly power bills.

2. The fundamental principle historically embedded in utility regulation in the United States is to provide consumers with *reliable* power at the *least* cost under applicable law. This principle is fair and compelling because the vast majority of American utility consumers are captive customers who pay a monopoly utility for a vital public service—electrical power—which no one can live without in modern society. Transmission is an essential component of this vital public service,[6] so necessary transmission must be built.

3. Today's final rule, however, is not about providing reliable power to consumers at least cost through just and reasonable rates as required by the FPA, despite the final rule's claim. And it is certainly not about being fair. On the contrary, the final rule inflicts staggering costs on consumers by promoting the construction of trillions of dollars of transmission projects,[7] not to serve consumers in accordance with the FPA, but to serve a major policy agenda never passed by Congress, to serve the profit-making interests of developers of politically preferred generation, primarily wind and solar, and to serve corporate ''green energy'' preferential purchasing policies.[8] As such, the final rule

generation.''). Further, FPA section 215, pertaining to electric reliability, explicitly leaves the construction of generation and transmission assets to state regulatory authority. 16 U.S.C. 824o(i)(2). Section 215 makes clear congressional intent to leave integrated resource planning to the states. Indeed, the overall statutory framework of the FPA—consistent with America's federal constitutional structure—makes it clear that *states* are the primary regulators of which utility assets get planned and built, both generation and transmission, not FERC.

[3] *See, e.g., W. Va.* v. *EPA,* 597 U.S. 697 (2022) (*West Virginia* v. *EPA*); *Dept. of Commerce* v. *N.Y.,* 139 S. Ct. 2551 (2019).

[4] In truly Kafkaesque fashion, the final rule is a doorstopper weighing in at just below 1300 pages, likely one of the longest, most complicated, and confusing orders the Commission has ever issued. Regulated entities—it applies to *all* public utility transmission providers in the United States, RTO and non-RTO—will need weeks just to read through it, much less decipher it, and then months of figuring out how to comply. Its very complexity raises the prospect of multiple rounds of compliance filings, no doubt punctuated by multiple deficiency letters, in order to push the transmission provider towards the outcomes the Commission wants to achieve. The final rule's very complexity renders it, if not arbitrary and capricious on its face, likely to be arbitrary and capricious in its enforcement.

[5] *See, e.g.,* Heather Richards, Zach Bright, Christian Robles, *3 energy issues to watch this spring at DOE, Interior and FERC,* Energywire, Mar. 18, 2024 (''FERC has promised a closely watched rule this spring on transmission that could be *key to President Joe Biden's ambitious aim to decarbonize the electricity grid by 2035* . . . . 'The sooner we get a final rule, the better. . .,' said Caitlin Marquis [of] Advanced Energy United, a pro-clean-energy group . . . . [T]he Biden administration is in a race . . . until roughly midyear to finalize rules *before they are subject to the Congressional Review Act (CRA)* . . . . The Biden administration has said [today's final rule] will facilitate a build-out of interregional lines and grid interconnections needed to . . . *allow more wind and solar power to come online* . . . .'') (emphases added) *https://www.eenews.net/articles/3-energy-issues-to-watch-this-spring-at-doe-interior-and-ferc/*; *see also* Peter Behr, *EPA power plant rule targets coal. Does that spell trouble for the grid?* Climatewire, May 3, 2024 (''But climate activists will not give up the 'zero by 2035' goal without a fight. President Biden made that steep commitment at a critical point in his 2020 candidacy to win the support of primary rival Sen. Bernie Sanders (I-Vt.) and his climate action activists . . . . [T]he hard road to a zero-carbon grid in 2035 is real *precisely because the Biden administration has pursued it* . . . . [Study authors] highlighted estimates that the rate of high-voltage transmission line construction *must double to deliver the necessary new wind and solar energy* . . . . The [Biden] administration . . . is putting a strategy for big new lines in place. *FERC, with the support of Biden appointees, is preparing new policy to support big wires projects* . . . . 'You can't get around the fact that *you're going to need tens of thousands of miles of new transmission lines if you want to build the hundreds of gigawatts of wind and solar and batteries that many of us predict are needed to achieve decarbonization goals,'* said [former Obama energy secretary Ernest] Moniz.'') (emphases added), *https://www.eenews.net/articles/epa-power-plant-rule-targets-coal-does-that-spell-trouble-for-the-grid-2/*; *see also* Zach Bright, *FERC sets date for landmark transmission rule,* Energywire, Apr. 19, 2024 (''FERC said it plans to hold a special May 13 meeting to consider its . . . transmission planning and cost-allocation proposal that's been a focus of *[lobbying] for expanding the grid to . . . move more renewable energy* . . . . *The Biden administration's goal of [net zero] by 2035 hinges on expanding the transmission system by two-thirds, the Energy Department said last year.*'') (emphases added), *https://www.eenews.net/articles/ferc-sets-date-for-landmark-transmission-rule/*; *It's raining rules: Why the Biden administration is rushing to produce regulations,* The Economist, May 4, 2024, at 19 (''More regulations, big and small, are expected soon. *The Federal Energy Regulatory Commission is planning to rewrite the rules governing interstate electricity transmission, which is critical to President Joe Biden's decarbonisation plans . . . . Why the sudden spate? A previously obscure law, the [CRA], helps explain the rush.* It allows Congress, for a limited period, to pass resolutions of disapproval against finalised administrative regulations with which it disagrees. If both chambers of Congress pass such a resolution, and the president signs it, the rule is cancelled, short-circuiting the usual drawn-out process of litigation or a subsequent administration beginning a whole new rule-making effort. So once a regulation is properly created the clock starts ticking: the cancellation procedure is allowed for up to 60 days that the Senate is in session—including the last 60 days of an administration that loses a presidential election.'') (emphasis added), *https://www.economist.com/united-states/2024/05/02/why-the-biden-administration-is-rushing-to-produce-regulations*; *see infra* nn.8, 10, 13, 15, 16, 67.

[6] The transmission component of utility service has typically been provided by the incumbent monopoly utility at the load-serving local level, and local transmission planning and/or construction is generally subject to state-regulated IRP or permitting processes, especially in non-RTO regions. The final rule imposes numerous additional requirements for local transmission planning, including even micromanaging how local ''stakeholder'' meetings are supposed to be conducted, which may conflict with state IRP proceedings and represent yet another FERC encroachment into areas of traditional state authority. *See Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Order No. 1920, 187 FERC ¶ 61,068, at Section IX.B.3.a (2024) (Final Rule). It is highly doubtful that the micromanagement of stakeholder meetings in local planning would pass judicial review under *CAISO* v. *FERC,* in which FERC's attempted micromanagement of an ISO's governing board appointments was rejected as not sufficiently grounded in FERC's rate-setting authority under the FPA. *See Cal. Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395, 400 (D.C. Cir 2004) (*CAISO* v. *FERC*).

[7] The Princeton Net Zero study is often cited, but it is only one of many estimates of the trillions of dollars in additional costs to be imposed on consumers. Using the Princeton study, the cost estimates of the transmission buildout necessary to achieve ''net zero'' range across different scenarios, with one scenario calling for transmission capacity to *quintuple (5x)* between 2020 and 2050, which is predicted to cost *$3.56 trillion. See* Princeton University Net Zero America Final Report Summary, Slide 29, *https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf.* I would emphasize that the sticker price of a utility asset is only a fraction of the ultimate cost to consumers, because the ''going in'' price will increase by a multiple of many times the original cost over the life of the asset, because the cost of capital, both a profit to the utility (known as Return on Equity, or ROE) and the cost of debt, will be paid by consumers. So, if Princeton gives an estimate of $3.56 trillion for new utility assets needed to reach the ''net zero'' goal, the *actual* cost to consumers over the life of the assets will be many times more than that estimate. *See also* Diana DiGangi, *U.S. won't reach net zero emissions without transmission buildout: DNV,* Utility Dive, Sept. 25, 2023 (''*$12 trillion* will be spent on clean energy in North America by 2050 . . . to meet . . . net zero emissions targets . . . . Some of the biggest barriers to net zero in the U.S. include the *lack of transmission buildout* . . . .) (emphases added), *https://www.utilitydive.com/news/net-zero-transition-clean-energy-north-america-transmission-buildout/694621/.*

[8] *See, e.g.,* Peter Behr, *DOE unveils critical grid corridors for Biden climate goals,* Energywire, May 8, 2024 (''*'To meet our climate goals we have to more than double our transmission capacity,'* said top White House clean energy adviser John Podesta, who has led a Cabinet-level push to get long-delayed transmission projects under construction.'') (emphasis added), *https://www.eenews.net/articles/doe-unveils-critical-grid-corridors-for-biden-climate-goals/*; Peter Behr, *More, More, More: Biden's clean grid hinges on power lines,* Energywire, May 23, 2022 (stating that ''the Biden administration is seeking an *unprecedented expansion of high-voltage electric lines to open new paths to wind and solar energy.* 'We obviously need *more, more, more transmission to run on 100 percent clean energy* . . .,' Energy Secretary

does not deserve a shred of deference under *Chevron U.S.A., Inc.* v. *Natural Resources Defense Council, Inc.*[9] in any form. Today's final rule is much less the product of reasoned decision-making or the agency's specialized expertise, as of political pressure and special interest lobbying.[10] In the chapter on ''regulatory capture'' [11] in future economics textbooks, today's final rule should be a featured case study.

4. The final rule orders *all* transmission providers, RTO and non-RTO, to plan costly regional transmission for some *allegedly predictable* generation mix 20 years in the future (a generation mix which, as a practical matter, is impossible to predict so far into the future).[12] The obviously pretextual agenda of the final rule, however, is not to *predict* the generation mix 20 years forward, but to *produce* the *preferred* generation mix that the current presidential administration, some huge multinational corporations,[13] some members of Congress, and other special interests want *now.* In fact, the final rule is not even about planning *transmission,* but is about planning *policy,* and it is very preferential about the policies it wants to promote. As with the Great Oz,[14] pulling back the curtain exposes the final rule for what it really is: An essential component in a comprehensive plan by the current presidential administration to push what the media describe as ''green policies'' designed to prefer and promote the wind and solar generation it favors while simultaneously *forcing* the shutdown of the fossil fuel generation it disfavors,[15] both needed to meet its political commitment. Let me emphasize: Whether the policies being promoted in this final rule can be described as ''green, purple, red or blue'' is irrelevant. The point is that FERC, as an *independent* agency, has no business promoting the policies of any one party or presidential administration, especially when, as here, the effort to do so goes far beyond FERC's legal authority and fails to perform our consumer protection function under the FPA.

5. Yet here's the legal rub with the final rule's pretextual agenda: *Congress never voted to amend the FPA* to *direct* or even *allow* FERC (which is supposed to be *independent*) to be what Energy Secretary Granholm describes as one of ''our partners across the administration'' in implementing this ''green energy'' transformation agenda.[16] Such a sweeping policy agenda, which involves the transfer of literally *trillions* of dollars of wealth from consumers to special interests, is the epitome of a major question

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Jennifer Granholm said in February.'') (emphasis added), *https://subscriber.politicopro.com/article/eenews/2022/05/23/more-more-more-bidens-clean-grid-hinges-on-power-lines-00030117; see also supra* n.5 and *infra* nn.10, 13, 15, 16, 67.

[9] 467 U.S. 837 (1984) (*Chevron*).

[10] *See* Catherine Morehouse, *FERC to tackle ''historic'' transmission planning rule in May,* PoliticoPRO, Apr. 18, 2024 (''FERC has been *under enormous pressure from lawmakers, clean energy developers, environmentalists and others* to finalize the rule that Chair Willie Phillips has promised will be 'historic' and the 'greatest development regarding electric transmission rules in the country in over a generation.' '') (emphases added), *https://subscriber.politicopro.com/article/2024/04/ferc-to-tackle-massive-transmission-planning-rule-next-month-00153191*; *see also, e.g.,* Sen. Charles E. Schumer July 24, 2023 Comments at 1–2 (urging the Commission to ensure that ''any final rule *must . . . prescribe* a set of benefits'' to be used in transmission planning and that ''it will be necessary that either'' [the transmission provider, or FERC *shall impose* cost allocation] ''when any state withholds support on a cost allocation method'' [which risks] ''*states that benefit from a transmission line*'' *[acting as]* ''*free riders [to] avoid any costs.*'') (emphases added); Sen. Martin Heinrich, et al. (consisting of 20 additional Senators) Jan. 19, 2024 Comments at 2 (urging the Commission that ''the final rule *must require* consideration of a . . . specific set of transmission benefits for . . . *cost allocation* processes'') (emphases added); Sen. Sheldon Whitehouse Nov. 7, 2023 Comments at 2 (stating that ''FERC should include [a list of required benefits] in its final rule''). As explained extensively herein, mandating benefits is a device for imposing costs on consumers in states that never agreed to the selection criteria or cost allocation. The deeply granular nature of the instructions to the Commission in these letters is more evidence that this final rule is a pretext to use an administrative agency to enact legislation that Congress never passed. *See also supra* nn.5, 8 and *infra* nn.13, 15, 16, 67.

[11] Luigi Zingales, *Preventing Economists' Capture,* University of Chicago Booth School of Business Review, July 1, 2014 (''In simple words, regulatory capture exists when a regulatory agency, created to act in the public interest, ends up advancing interests of the industry it is charged with regulating.''), *https://www.chicagobooth.edu/review/preventing-economists-capture*.

[12] The example of the Potomac-Appalachian Transmission Highline (PATH) fiasco is a strong warning about the folly of spending billions of consumers' dollars to build transmission based on predictions of a generation mix in 20 years. *Potomac-Appalachian Transmission Highline, LLC,* 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring at P 3) (PATH Concurrence) (''[C]onsumers have paid roughly *$250 million* for a project that was never built nor found needed by a single state regulator.'') (emphasis in original), *https://www.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12*; *see also* PJM Initial Comments at 62 (''In short, the volatility of input parameters cancelled the need for a $1.8 billion transmission line identified in 2007, that was confirmed to be needed five years out in 2012, but by 2012 was no longer needed for at least another 15 years, if at all.''). Rather than wind or solar—which the final rule implicitly presumes will be the predominant generating resource in 20 years—it is just as foreseeable that the predominant share of generation in the U.S. could be nuclear, an essential dispatchable resource, as small modular reactor technology matures and economies of scale produce lower costs, or it could be green hydrogen. It could even be fusion or some new technology currently either nascent or unknown. *No one knows today.* Building trillions of dollars of transmission on a *prediction* that intermittent wind and solar will be the predominant generating resource in 20 years is just a costly guess.

[13] *See, e.g.,* Clean Energy Buyers Jan. 22, 2024 Comments (''Many of our businesses cannot grow without more *clean generation* resources . . . . States may miss out on economic growth opportunities without . . . access to the *types of generation resources* needed to attract growing and innovative industries.'') (emphases added). Among the signers of these comments were Amazon, Apple, eBay, Google, Green Impact Technologies, Meta, Microsoft, Nike, Rivian, Salesforce, Target, Walmart and several other multinational corporations. The FPA gives FERC no authority whatsoever to use the ''green energy'' purchasing preferences of privately owned, for-profit multinational corporations as the basis to impose a *mandatory* transmission planning and cost allocation rule that will cost consumers trillions of dollars. The FPA does not recognize such corporate preferences; indeed, the FPA *forbids* preferences. *See also supra* nn.5, 8, 10 and *infra* nn.15, 16, 67.

[14] *The Wizard of Oz* (Metro-Goldwyn-Mayer 1939).

[15] *See, e.g.,* Catherine Morehouse, *DOE launches effort to cut federal permitting for new power lines in half,* PoliticoPRO, Apr. 25, 2024 (''The [U.S. Dept. of Energy] program is the *latest move by the Biden administration to speed up the . . . process for new transmission lines deemed critical to carrying dispersed wind and solar resources . . . . It also comes on the heels of an announcement from the EPA to tighten emissions standards for fossil-fueled power plants*—a move that will necessitate bringing more low-carbon resources onto the power grid to meet growing demand *as [fossil fuel] resources are forced offline.* 'DOE's work complements *what our partners across the administration are doing* . . . to deliver cleaner power . . . ,' Energy Secretary Jennifer Granholm told reporters . . . .'') (emphases added), *https://subscriber.politicopro.com/article/2024/04/doe-launches-effort-to-cut-federal-permitting-for-new-power-lines-in-half-00154189*; *see also* Catherine Morehouse, *Energy regulator's exit may flummox Biden's green plans,* Politico, Feb. 9, 2024 (''[FERC] is poised to lose its biggest climate advocate and potentially shut down one of the White House's *best avenues to push its green policies. . . .* That buildout is needed to accommodate . . . *wind and solar projects that are critical to meeting the Biden administration's climate and clean energy goals.*'') (emphases added), *https://subscriber.politicopro.com/article/2024/02/energy-regulators-exit-may-flummox-bidens-green-plans-00140774*; Molly Christian, *US transmission ''in desperate need of an upgrade,'' Vice President Harris says,* Megawatt Daily, Jan. 20, 2023 (''Achieving lofty US climate goals will *require* '*thousands of miles of new high-voltage transmission lines all across our country,*' US Vice President Kamala Harris said . . . . '*To create our clean energy future, we must construct thousands of miles of new high-voltage transmission lines all across our country,*' [Harris said].'') (emphases added), *https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/012023-us-transmission-in-desperate-need-of-an-upgrade-vice-president-harris-says*; Alex Guillén, Ben Lefebvre, Annie Snider, Kelsey Tamborrino, Catherine Morehouse, James Bikales, *Biden administration eyes spring to finalize key climate regulations,* PoliticoPro, Dec. 6, 2023 (''The Biden administration is planning to finalize several major energy and environmental regulations in the first half of 2024 . . . . *That timeframe would help cement many of President Joe Biden's policy priorities in the event he does not win reelection* . . . . One of the top [FERC] priorities . . . has been to finalize a rule on power line planning and cost allocation . . . . *that is considered critical to unlocking new wind and solar resources.*'') (emphases added), *https://subscriber.politicopro.com/article/2023/12/biden-administration-plots-busy-spring-finalizing-key-climate-regulations-00130496. See also supra* nn.5, 8, 10, 13 and *infra* nn.16, 67.

[16] *See* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines,* The New York Times, Apr. 25, 2024 (''[Biden] Administration officials are increasingly worried that their plans to fight climate change could falter unless the nation can quickly add *vast amounts of grid capacity to handle more wind and solar power* . . . . But experts say a rapid, large-scale expansion *may ultimately depend on Congress.*'') (emphases added), *https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html. See also supra* nn.5, 8, 10, 13, 15 and *infra* n.67.

of public policy under *West Virginia* v. *EPA.* The final rule clearly intends to socialize trillions of dollars of costs for the transmission necessary to pursue this transformational agenda, and unlike the NOPR,[17] the final rule removes the principle that the states must consent to how and whether these massive costs are imposed on their consumers. The final rule goes to great lengths to use ''nothing to see here'' rhetoric,[18] but looking behind the curtain at what is really going on makes it obvious that the final rule is pretextual and a blatant violation of the major questions doctrine.[19] In its transparent effort to plan and fund trillions of dollars' worth of transmission to facilitate a *preferred* generation mix predominantly of wind and solar, both for public policies as well as corporate purchasing preferences, it is also ''preferential'' and thus a clear violation of FPA section 206.

6. Put most simply, the final rule is a shell game that plays this way:

Step One: For planning and cost allocation purposes, throw transmission projects that solve specific reliability problems or reduce congestion costs into the same bucket as projects designed to promote public policies or corporate ''green energy'' preferences and disguise the purpose of very different projects by re-labeling *all* projects in the new bucket with the innocuous-sounding name ''Long-Term Regional Transmission Facilities.''

Step Two: Mandate planning inputs that must be used in determining which projects get selected for regional plans, which starts the money flowing from consumers to developers before any state has even evaluated the need for, or cost of, the projects.

Step Three: Mandate benefits that will ultimately affect the allocation of costs to consumers across a multi-state region. Combined with Steps One and Two, this makes consumers involuntary ''beneficiaries'' who will then be forced to pay for projects that promote another state's public policy or corporate ''green power'' commitments.

Step Four: Order all transmission providers to develop and file a cost allocation formula that will automatically be the default applicable to the entire bucket of Long-Term Regional Transmission Facilities.

Step Five: Remove the NOPR's requirement that states must consent to the details of Steps One through Four before their consumers can be burdened with costs.

7. Let's drill down on the details of the final rule's shell game. The final rule seeks to shift the costs of transmission projects whose purpose is to implement state or local public policies promoting wind and solar generation (commonly referred to as ''public policy projects'' or ''policy-driven projects'') and big corporation ''green energy'' preferences by putting those projects into the same regulatory bucket—both for planning *and* cost-allocation purposes—with fundamentally different types of projects, those designed either to solve identified *reliability* problems (an engineering purpose, not a political or corporate purpose) or to provide quantifiable congestion cost savings (*economic* projects).[20] The final rule labels *all* projects thrown into the new bucket as ''Long-Term Regional Transmission Facilities.''[21] Lumping policy-driven projects with the other very different types of projects is a sleight-of-hand move to disguise the costs of the policy-driven and corporate-driven projects that the final rule is promoting.[22] Put most simply, reliability projects are driven by engineering, economic projects by economics, public policy projects by politicians, and corporate ''green energy'' policies by management and investors looking to maximize their returns or satisfy investment goals not recognized by the FPA.

8. Then to further promote its preferred policy projects, the final rule mandates planning criteria to be used in the planning of Long-Term Regional Transmission Facilities,[23] including the ''categories of factors'' that must be used in developing long-term planning scenarios[24] and the list of benefits that must be used by planners in cost-benefit analyses.[25] All of these mandatory features are transparently intended to ''pre-cook'' outcomes by manipulating the planning and evaluations that determine which projects are selected for regional transmission plans. (It is emblematic of the entire final rule that it did *not* include ''saves retail customers money'' as one of its mandatory benefits for evaluating projects.)[26] The shell game's purpose is to ensure that preferential policy and corporate-driven projects are selected for regional transmission plans, which conveniently ensures that such projects are eligible for cost recovery through FERC's very generous (to developers, not consumers) formula rate mechanism. As further proof of the nature of the shell game, the final rule does not require transmission providers to identify the benefits used (other than those mandated), or how those benefits were specifically calculated, for cost allocation purposes.[27] While the final rule insists that it is not mandating *outcomes,* when you manipulate the *inputs* of transmission planning, you are effectively mandating outputs.[28]

9. But that's not all; here comes the worst part of the shell game. The final rule then requires every transmission provider in America to file an *ex ante* cost allocation formula that is applicable to the whole bucket of projects,[29] which now includes public and corporate-driven policy projects, ***in order to socialize the costs of these projects across the entire region, even when states in a region have never consented for their consumers to bear the costs of such projects.*** The final rule seeks to justify this

[17] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Notice of Proposed Rulemaking, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028, at P 303 (2022) (NOPR).

[18] *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at P 265 (''[W]hat matters is that this final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission's jurisdiction under the FPA.'').

[19] *See infra* Section III.C. The final rule insists that it most assuredly does *not* implicate a major question of public policy, Final Rule, 187 FERC ¶ 61,068 at PP 275–279, much like Captain Renault in *Casablanca* is ''shocked, *shocked* to find gambling going on in here'' as he pockets his winnings. *Casablanca* (Warner Bros. Pictures 1942); *but see* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines,* Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, '' 'I've called [the final] rule the *biggest energy policy in the country.*' '') (emphasis added), *https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html. See* Catherine Morehouse, *FERC to tackle ''historic'' transmission planning rule in May,* PoliticoPRO, Apr. 18, 2024 (quoting Chairman Phillips describing the final rule as ''*historic*'' and the ''*greatest development regarding electric transmission rules in the country in over a generation* . . . .'') (emphases added).

[20] *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 1474 (''[T]ransmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types.'').

[21] *Id.; see also id.* PP 41, 250–251. In terms of labeling, at least Order No. 1000 described public policy projects honestly, as those that address ''transmission needs driven by Public Policy Requirements.'' *See, e.g., Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.,* Order No. 1000, 136 FERC ¶ 61,051, at PP 2, 6 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g & clarification,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014) (*South Carolina*); *see also id.* PP 11, 47.

[22] *See PJM Interconnection, L.L.C.,* 187 FERC ¶ 61,012 (2024) (Christie, Comm'r, concurring at P 6 n.12) (''I note too that in PJM's [Regional Transmission Expansion Plan (RTEP)] review it offers a good example of how components of two different types of projects, a specific reliability solution and [State Agreement Approach (SAA)] Project, can be combined into one project that meets both needs. PJM describes in its filing how it solved a Window 3 specific reliability problem by combining that solution with an SAA project into an Incremental Multi-Driver Project . . . . This is a good example of how a multi-driver project should work: The reliability need is specific and would require a specific reliability solution that would, on its own, merit inclusion in the RTEP as a reliability project, and the SAA project, which is a supplemental—not a reliability—project, if feasible as it is in this specific case, can be planned in a way to meet the specific reliability need. Costs are allocated by PJM proportionately to each component of the project, one percentage allocated as a reliability project under PJM's formula, the other percentage wholly allocated to New Jersey for the SAA project.'') (internal citation omitted).

[23] Final Rule, 187 FERC ¶ 61,068 at Section III.

[24] *Id.* P 409. Among the *mandatory* categories of factors that the final rule dictates must be used to drive long-term planning throughout the entire country are, *inter alia:* (i) *state and local laws affecting the resource mix,* (ii) state and local laws on *decarbonization,* (iii) generator interconnection requests and withdrawals (another way to subsidize and prefer wind and solar developers which dominate the queues), and (iv) *corporate,* state and local government commitments to *purchase ''green'' energy.* Let me emphasize: these planning factors are *mandatory* for transmission providers to use, exposing the final rule's pretextual agenda for what it really is.

[25] *Id.* PP 3, 269, 719–720.

[26] *See, e.g., id.* P 720.

[27] *Id.* PP 1505–1511.

[28] *Id.* P 965.

[29] *Id.* P 1291.

imposition of costs on non-consenting states by treating their consumers as ''cost causers'' or ''beneficiaries,'' [30] which is justified by—now circle back to earlier in the shell game—the final rule's imposition of mandatory factors and benefits that must be used in the evaluations of projects.[31] By lumping reliability and economic projects into the same planning bucket as public and corporate-driven policy projects, the final rule seeks to affix the tags of ''cost causer'' and ''beneficiary'' to *all* consumers in a multi-state region, to justify sticking them with costs even if their state officials never consented. So despite the final rule's disingenuous claims to the contrary,[32] the intent and effect of this shell game is to enable the costs of corporate and public policy-driven projects to be socialized across an entire multi-state region and thus shifted onto consumers in states that never agreed to bear such costs. The *explicit* promise of the NOPR, that states would have to *consent* for their consumers to bear such costs, has been broken in this final rule.

10. When I voted for the NOPR, I made it absolutely clear I was voting for it because it reflected a *compromise* in which public and corporate policy-driven projects could be incorporated into long-term planning, but *only if* the states had the authority to consent *both* to planning criteria, including benefits used in cost-benefit analyses to evaluate projects and selection criteria, as well as to cost allocation.[33] In my concurrence to the NOPR I wrote:

Even more importantly though, for these [long-term] projects, the NOPR proposes to *require* the regional planning entities to consult with and *seek the agreement of the relevant states to both the selection criteria for these projects and to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies.* The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects—such as, for example, the ''highway-byway'' formula approved by the SPP Regional State Committee—or states can agree to a process for a project-by-project agreement on cost allocation among one or several states—such as, for example, the State Agreement Approach in PJM—or states may choose some combination of both.[34]

And let me emphasize . . . *no individual state's consumers can be forced to bear the costs of another state's policy-driven project or element of a project against its consent.*[35]

The bottom line for me is this: I believe that elevating the role in planning and cost allocation of state regulators—*who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component*—will make it *more likely, not less,* that necessary transmission can get built *while ensuring that rates resulting from these types of policy-driven projects will not be unjust and unreasonable, which they clearly have the potential to be.*[36]

The other members of the Commission, including the then-Chairman and both other members of today's Commission, also recognized the NOPR as a compromise.[37]

11. Yet the many fundamental changes made in this final rule [38] subvert and violate that compromise. Of particular importance to my willingness—and that of many state regulator organizations—to support the compromise NOPR, was the explicit principle of state agreement to planning and selection criteria and cost allocation embodied in the NOPR. The final rule, however, *denies what the NOPR promised:* it denies state agreement to selection criteria,[39] it denies state agreement to the benefits to be used in evaluating projects for selection in regional plans and ultimate selection (which can start the money flowing from consumers to developers before a state siting or construction permit has even been issued),[40] and most importantly, it denies state agreement to cost allocation for public policy and corporate-driven projects.[41] The State Agreement Approach, used successfully in PJM for over a decade, is effectively terminated by the final rule. The final rule says that, *even if states in a planning region agree,* a ''State Agreement Process'' *cannot* be the sole chosen method for allocating costs of these projects; the transmission provider's own *ex ante* formula *must* be the default method, regardless of whether states have agreed to it.[42] In addition to a *de facto* termination of the PJM State Agreement Approach, the final rule could call into question mechanisms to facilitate the states' role in cost allocation that have been used in other RTOs and ISOs for years, including in SPP and MISO.[43]

12. And let's get real: Telling the states to negotiate for an alternative cost allocation when the transmission provider's *ex ante* formula has already been designated as the default is no real negotiation at all. The final rule points a regulatory gun at states' heads redolent of *The Godfather:* [44] ''Here's an offer

[30] *See, e.g., id.* P 1305 n.2786 (''The cost causation principle requires costs to be allocated to those who *cause* the costs to be incurred and *reap the resulting benefits.*'') (emphasis added). A true statement on its face, but utterly disingenuous here. By mandating its preferred factors to be used in long-term planning, by mandating certain benefits to be used in evaluating projects, and by denying transparency as to what other benefits are used to evaluate projects and *how* benefits are being calculated, which drives cost allocation, the final rule effectively will hide the specific costs of policy and corporate-driven projects and essential information as to how costs are being calculated and allocated across a multi-state region. *See also supra* n.10.

[31] These key elements of the shell game respond almost precisely to the lobbying demands of various interest groups. *See, e.g.,* Environmental Groups Dec. 8, 2023 Comments (''Transmission providers *must* perform long-term (at least 20-year), forward-looking assessments . . . . They *must* . . . [include] planning for *state clean energy laws and policies, [and] scenarios with high renewable penetration* . . . . Scenarios *must* evaluate all benefits that transmission projects would deliver and *use these assessed benefits as a basis for project selection* . . . . The Commission also should create a *default cost allocation* policy that meets this same standard . . . .'') (emphases added). Among others, the signers of this letter include: Advanced Energy United, American Clean Power Association, Clean Air Task Force, Earthjustice, Environmental Defense Fund, Evergreen Action, League of Conservation Voters, National Wildlife Federation, Natural Resources Defense Council (NRDC), Sierra Club, Union of Concerned Scientists, and WE ACT for Environmental Justice. *See also supra* nn.8, 10.

[32] Final Rule, 187 FERC ¶ 61,068 at P 267 (''[N]othing in this final rule requires states to subsidize other states' public policies and, indeed, this final rule requires . . . that transmission customers within a transmission planning region need only pay costs that are 'roughly commensurate' with the benefits that *transmission providers estimate* they will receive from a transmission facility.'') (emphasis added).

[33] NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at PP 11–12, 14) (NOPR Concurrence); *see also id.* P 5.

[34] *Id.* P 11 (emphasis in original and added).

[35] *Id.* P 12 (emphasis added).

[36] *Id.* P 14 (emphasis in original and added).

[37] From the Transcript of Apr. 21, 2022 Commission Open Meeting (April 2022 Open Meeting Tr.):

''CHAIRMAN GLICK: And I also want to finally thank my colleagues. I think this [NOPR] is a *really good product.* It is a product of a lot of discussion, *a lot of compromise*—which is what *the Commission is all about*—and I think *all of us can say we did not get everything in there, in the document, that we would like, but I think we all got enough in there and I think we achieved a significant and really remarkable level of consensus.* And I think that is very notable today.'' April 2022 Open Meeting Tr. 44:17–24 (emphases added).

''COMMISSIONER CLEMENTS: As the Chairman [stated] that reaching agreement on this proposal was not easy. I can say with confidence that *none of us voting for it would have written it this way if we were writing on our own. But I am proud that it is a bipartisan effort,* and I am thankful to my colleagues for proactively engaging and for thinking creatively to find alignment.'' *Id.* at 55:17–23 (emphasis added).

''COMMISSIONER CHRISTIE: But I think on balance the positive aspects of this [NOPR], *particularly for state regulators at the heart of planning and cost allocation for these types of projects,* changing [CWIP] to AFUDC[,] I think those are *positive, big steps forward for me on balance and it makes it worth voting for this [NOPR].*'' *Id.* at 67:15–20 (emphasis added).

''COMMISSIONER PHILLIPS: I would first like to thank my colleagues for working collaboratively with me on this. . . . I don't think I have ever been a part of a process more collaborative than this process that we had in this NOPR.'' *Id.* at 67:24–25, 68:6–8.

To those who say that many elements of this final rule were also in the NOPR for which I voted, such as, for example, the mandatory categories of factors, I would respond: If I agree to get a root canal with anesthetic, but learn upon arrival at the dentist's office that I can still get the root canal but with no anesthetic, that is not the original deal.

[38] *See infra* Section II.

[39] Final Rule, 187 FERC ¶ 61,068 at P 996.

[40] *Id.* PP 3, 269, 719–720, 903.

[41] *Id.* PP 1291–1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

[42] *Id.* To be clear, even if the states agreed on an alternative *ex ante* cost allocation method, or if they agreed on a cost allocation method under the State Agreement Process, the transmission provider could choose to file it but also *could ignore it. See infra* n.195.

[43] *See* Final Rule, 187 FERC ¶ 61,068 at PP 1291–1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

[44] *The Godfather* (Paramount 1972).

you can't refuse.'' And contrary to NARUC's eminently reasonable and practical request,[45] the final rule even requires only one Engagement Period for states to negotiate a different cost allocation from the transmission providers' *ex ante* cost allocation before that *ex ante* cost allocation becomes the default.[46] It is obvious that the final rule intends to lock in each transmission provider's own *ex ante* formula for many years to come and to deny states any avenue to challenge it even as times and circumstances change, no matter how high their consumers' power bills escalate due to rising transmission costs.

13. Essentially, the final rule replaces the NOPR's principle of requiring state agreement to selection criteria, benefits, and cost allocation with a charade of suggesting to transmission providers that they ''consult with and seek support'' from the states—while paradoxically ''clarifying'' that transmission providers do not actually need to obtain state consent—and the final rule uses other empty phrases such as allowing states to ''inform'' or ''provide input on'' the evaluation process and cost allocation.[47] But the final rule's real attitude towards the states and state regulators is embodied in this airily regal but perhaps unintentionally straightforward pronouncement: ''[W]e do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive.''[48]

14. The principle of cost allocation that was described in my concurrence to the NOPR—that states must consent to regional cost allocation of corporate and public policy-driven projects—reflects a core principle of American democracy: *fairness.* In this ratemaking context, fairness means that the people have the right to choose the policymakers who impose costs on them, so they can hold them accountable. This final rule is *unfair* because it gives FERC and the transmission providers it regulates the power to *impose* costs on consumers to pay for transmission driven by huge corporations and politicians in states other than theirs, and for whom they never voted. The final rule truly subverts the principle that the people, through their state's policymakers, must consent to bear the costs of another state's politicians and their policy choices, or the energy purchasing preferences of corporate managers and investors.

15. And from the consumer standpoint, the timing of this rule could not be worse. American residential customers will pay about 16.23 cents per kWh next year, the *highest retail power cost for consumers in almost three decades.*[49] Unlike in years past, fuel costs are not the primary driver of these mounting prices to consumers; rather, transmission is. Transmission costs are rising rapidly, becoming an ever more burdensome part of consumers' power bills.[50] To cite just one major example, in PJM, the largest RTO by load in the country, the transmission component of wholesale power costs has essentially *tripled* over the past decade, from just $5.65/MWh in 2013 to $16.54/MWh last year. Transmission now constitutes almost a third of wholesale power costs, up from approximately 10% just a decade earlier.[51] In 2020, the PJM Market Monitor reported that the cost of transmission exceeded the cost of capacity for the first time.[52] Nationally, transmission rate base nearly tripled in a decade,[53] and—assuming an 8.2% year-over-year growth rate, which occurred in 2022—is on track to double again in the next nine years, even without this rule's intent to spend trillions more on transmission. According to the U.S. Energy Information Administration, already one in three American households reports difficulty in paying their power bills.[54]

16. Don't fall for the absurd claim that this rule will somehow save consumers money through more holistic or efficient planning, a vacuous bureaucratic argument divorced from reality.[55] The sheer amount of new transmission costs that the final rule inflicts on consumers—and special interest groups want—is staggering, measured in the *trillions,*[56] not 'merely' hundreds of billions, of dollars.[57] And these staggering costs will not be incurred to provide consumers with reliable power, but to serve political and corporate agendas. It is truly Orwellian newspeak[58] to claim that adding multiple trillions of dollars in transmission costs to consumer's bills will somehow ''save'' consumers money (even Orwell would be impressed at the sheer audacity of such a claim).

17. If FERC were seriously interested in saving consumers' money, it would be acting to rein in the wide array of transmission incentives regularly handed out to transmission developers that are direct transfers of wealth from consumers to developers (long known as ''FERC candy''),[59]

[45] Final Rule, 187 FERC ¶ 61,068 at P 1255 (''NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Facilities.'' (citing NARUC Initial Comments at 49–50)).

[46] *Id.* P 1368; *see also id.* P 1291.

[47] *See, e.g., id.* PP 268, 959, 994, 996–997, 1456.

[48] *Id.* P 1363 (citation omitted). A different attitude towards state regulators was apparent in the NOPR. *See* April 2022 Open Meeting Tr. 46:10–16 (''CHAIRMAN GLICK: [This] NOPR proposes to give the states a much more significant role in addressing cost allocation. I think it helps to have Commissioner Christie and Commissioner Phillips, two of our five Commissioners are former state regulators, and I think that really helps to have their background and their interest.'').

[49] *See* Robert Walton, *U.S. electricity prices outpace annual inflation,* Utility Dive, Mar. 13, 2024 (''U.S. electricity prices rose 3.6% over the last 12 months, outstripping the broader inflation rate of 3.2%, the Bureau of Labor Statistics reported Tuesday. And experts say *there is little chance for near-term consumer relief.* . . . And *federal policies aimed at electrifying end uses and reducing emissions could lead to even higher prices,* Travis Fisher, director of energy and environmental policy studies at the Cato Institute, told a House subcommittee Wednesday.'') (emphasis added), *https://www.utilitydive.com/news/us-electricity-prices-rise-customer-eia-outlook/710113/.*

[50] *See, e.g.,* Zach Bright, *Electricity prices rise faster than inflation, EnergyWire,* Apr. 12, 2024 (''The Bureau of Labor Statistics found that electricity prices rose 5 percent over the past year. *That's higher than the overall consumer price index (3.5 percent) and any other single commodity, like food . . . and gasoline* . . . .'') (emphases added), *https://www.eenews.net/articles/electricity-prices-rise-faster-than-inflation/*; *Electricity Inflation 30% Higher Than CPI Over Last 12 Months*'' Electricity Transmission Competition Coalition, Apr. 10, 2024 (''Electricity inflation remains the highest consumer goods cost among the items in the Consumer Price Index according to the latest release of data by the Bureau of Labor Statistics. . . . The price of electricity has soared because of the *accelerating cost of transmission* . . . .'') (emphasis added), *https://electricitytransmissioncompetitioncoalition.org/electricity-inflation-30-higher-than-cpi-over-last-12-months/.*

[51] State of the Market Report 2023, PJM Market Monitor, Vol. II, Section 1, at 18, Table 1–9, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml*; State of the Market Report 2014, PJM Market Monitor, Vol. II, Section 1, at 16, Table 1–9, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec1.pdf*; State of the Market Report 2013, PJM Market Monitor, Vol. II, Section 1, at 12, Table 1–9, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-sec1.pdf*; *see also* State of the Market Report 2019, PJM Market Monitor, Vol. II, Section 1, at 18, Table 1–10, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec1.pdf.*

[52] State of the Market Report 2020, PJM Market Monitor, Vol. I, at 17, Table 8, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf.*

[53] *See* Jim O'Reilly, *Led by AEP and Duke, transmission growth poised to rebound from dip in 2022,* S&P Global Market Intelligence, Nov. 15, 2023 (showing bar graph providing that aggregate transmission rate base grew from $61.4 billion in 2012 to $163.1 billion in 2022), *https://www.spglobal.com/marketintelligence/en/news-insights/research/led-by-aep-and-duke-transmission-growth-poised-to-rebound-from-dip-in-2022.* Under this Commission's rate recovery protocols, the transmission owner gets to collect the annual costs of transmission depreciation from rate base, plus a profit, known as Return on Equity, or ''ROE,'' often inflated by the many incentives the Commission typically approves, as well as operations and maintenance costs. As any utility regulator knows, ''what goes into rate base comes out in customers' bills.'' So a rapidly rising rate base means rapidly growing consumers bills.

[54] Amanda Durish Cook & Tom Kleckner, *Overheard at 10th Annual GCPA MISO–SPP Forum,* RTO Insider, Mar. 12, 2024, *https://www.rtoinsider.com/73311-overheard-10th-annual-gcpa-miso-spp-forum/.*

[55] *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at P 89.

[56] *See supra* n.7.

[57] Illinois Senator Everett Dirksen is said to have once quipped, ''In Washington, a billion here, a billion there, and pretty soon you're talking about real money.'' The final rule updates his quip to a ''trillion here, a trillion there . . . .''

[58] George Orwell, *1984* (first published by Secker & Warburg 1949).

[59] *See, e.g., Office of Ohio Consumers' Counsel* v. *Am. Elec. Power Serv. Corp.,* 181 FERC ¶ 61,214 (2022) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-addressing-rto-adders-related-e-2-ohio*; *MISO,* 181 FERC ¶ 61,094 (2022) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-urging-action-re-rto-participation-adder-docket*; Mary O'Driscoll, *FERC approves incentives for AEP, Allegheny grid projects,* Greenwire, July 21, 2006 (''The approvals came as the commission finalized rules intended to promote transmission-grid additions that outline specific rate and other incentives that FERC will consider for future construction projects—the *'FERC candy'* that critics contend gives the utilities incentives but not much in the way of corresponding requirements.'') (emphasis added),

and acting to reform the automatic awarding of the presumption of prudence in formula rate proceedings. Literally *nothing* is being done about these forms of consumer exploitation in this final rule; instead, the final rule goes in the exact opposite direction.

18. To add further insult to consumers' injury, the final rule *walks back* the NOPR proposal that would have denied transmission developers the Construction Work in Progress (CWIP) incentive.[60] I have written many times that CWIP is simply unfair. CWIP is unfair because it makes consumers the unwilling ''bank'' for developers, but unlike a real bank, consumers don't get paid any interest and this Commission forces them to make involuntary loans.[61] Removing CWIP was strongly supported by those concerned with protecting consumers: by state regulators, by public power providers, and by state consumer advocates.

19. In my concurrence to the NOPR, I wrote:

CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the developer. CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer. . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does. *This NOPR proposal represents a major step forward in consumer protection and is a big reason I am voting for it.*[62]

By walking back the proposed CWIP denial, the final rule results in a *major step backwards* for consumers.[63]

20. In yet another major slap at consumers, the final rule seeks to shift the substantial costs caused by generation developers' interconnection requests from developers to consumers.[64] It does this by ordering transmission providers to revise their regional transmission planning processes to evaluate for selection regional transmission facilities that address identified interconnection-related transmission needs, and the final rule specifies that if such a facility is selected, *its costs will be regionally allocated*.[65] It also does this by ordering transmission providers to incorporate generator interconnection requests and withdrawals in their long-term transmission planning.[66] These are only schemes to shift interconnection costs from developers to consumers and will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential. Similarly, the final rule also inappropriately shifts preferential corporate-driven project costs onto *all* other consumers, who may disagree with, or even compete against, the corporate customers imposing their preferences. These provisions alone render the final rule's replacement rate unlawful under FPA section 206.

21. This Commission is, by statute, supposed to be *independent* of any presidential administration, but it has failed to defend that independence in this final rule, which is a naked pretext to enact the current administration's ''net zero 2035'' policy agenda, as well as to serve corporate agendas, and those of other profit-seeking special interests.[67] In failing to act independently,[68] this Commission has broken faith with state regulators and, even more importantly, broken faith with tens of millions of American consumers, who could be forced to bear literally trillions of dollars in costs for transmission lines to serve political, corporate and other special-interest agendas. This will not produce just and reasonable rates and is grossly unfair. This final rule is a dereliction of the Commission's duty under the FPA to protect consumers and far exceeds its authority under that statute.

II. The Final Rule Is Fundamentally Different From the NOPR

22. The very essence of due process is notice and opportunity to be heard. Given the large number of fundamental changes to the NOPR, the final rule should be viewed as effectively a second NOPR and clearly should have been put out for additional public comment on the many fundamental changes. Because it was not, deliberately so, this final rule invites a court to remand with instructions for the Commission to give the public an opportunity to comment on the many fundamental changes from the NOPR.

23. The final rule issuing today is not the NOPR for which I voted. This pretextual final

https://subscriber.politicopro.com/article/eenews/2006/07/21/ferc-approves-incentives-for-aep-allegheny-grid-projects-234508.

[60] Final Rule, 187 FERC ¶ 61,068 at P 1547.

[61] *Baltimore Gas & Elec. Co.,* 187 FERC ¶ 61,030 (2024) (Christie, Comm'r, dissenting at P 7), *https://www.ferc.gov/news-events/news/commissioner-christies-dissent-award-incentives-exelon-er24–1313*; *PJM Interconnection, L.L.C.,* 185 FERC ¶ 61,200 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/e-7-commissioner-christies-concurrence-exelons-application-abandoned-plant*; *The Potomac Edison Co.,* 185 FERC ¶ 61,083 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-potomac-edisons-abandoned-plant*; *Montana-Dakota Utils. Co.,* 185 FERC ¶ 61,015 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-montana-dakota-utilities-co-regarding*; *Midcontinent Indep. Sys. Operator, Inc.,* 184 FERC ¶ 61,136 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc-0*; *GridLiance W. LLC,* 184 FERC ¶ 61,129 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-gridliance-west-regarding-transmission*; *Midcontinent Indep. Sys. Operator, Inc.,* 184 FERC ¶ 61,034 (2023) (Christie, Comm'r, dissenting at P 8), *https://www.ferc.gov/news-events/news/commissioner-christies-dissent-award-transmission-incentives-nipsco-er23–1904*; *Otter Tail Power Co.,* 183 FERC ¶ 61,121 (2023) (Christie, Comm'r, concurring at P 8), *https://www.ferc.gov/news-events/news/e-18-commissioner-christies-concurrence-otter-tail-power-company-regarding*; *LS Power Grid Cal., LLC,* 182 FERC ¶ 61,201 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-ls-power-grid-regarding-transmission-incentives*; *Nev. Power Co.,* 182 FERC ¶ 61,186 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nv-energy-regarding-transmission-incentives*; *The Dayton Power and Light Co.,* 182 FERC ¶ 61,147 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-dayton-power-and-light-company-regarding*; *Midcontinent Indep. Sys. Operator, Inc.,* 182 FERC ¶ 61,039 (2023) (Christie, Comm'r, concurring at P 3), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc*; *NextEra Energy Transmission Sw., LLC,* 180 FERC ¶ 61,032 (2022) (Christie, Comm'r, concurring at P 3) (July 2022 Concurrence), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nextera-energy-transmission-southwest-llc*; *NextEra Energy Transmission Sw., LLC,* 178 FERC ¶ 61,082 (2022) (Christie, Comm'r, concurring at P 3) (February 2022 Concurrence), *https://www.ferc.gov/news-events/news/commissioner-mark-c-christie-concurrence-nextera-energy-transmission-southwest-llc.*

[62] NOPR Concurrence at P 15.

[63] By doing nothing about the consumer-paid ''FERC candy'' incentives that this Commission regularly hands out to developers, and even removing the provisions dialing back the CWIP incentive—and with its overall aim to pile trillions of dollars of additional costs for big corporate and politically-driven transmission on consumers, which will largely flow to the increased profits of wind, solar and transmission developers—the final rule could be the inspiration for one of the great country and western songs ''Lord Have Mercy on the Working Man.'' Warner Bros. Nashville 1992 (''Why's the rich man busy dancing while the poor man pays the band? Oh they're billing me for killing me, Lord have mercy on the working man!'').

[64] Final Rule, 187 FERC ¶ 61,068 at PP 472, 1106–1107, 1126, 1145.

[65] *Id.* PP 125, 1106–1107, 1126, 1145. Under ''participant funding'' mechanisms the generation developer pays the costs of the network upgrades costs it causes and consumers do not pay, which is only fair. The Commission's Order No. 2023 did not violate this principle. *See generally Improvements to Generator Interconnection Procs. & Agreements,* Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, *order on reh'g,* 185 FERC ¶ 61,063 (2023), *order on reh'g,* Order No. 2023–A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199 (2024). This final rule clearly intends to undermine this principle by moving interconnection costs into regional transmission planning and cost allocation, so consumers get stuck with the costs of interconnection, even though it is developers who profit from interconnection.

[66] Final Rule, 187 FERC ¶ 61,068 at P 472.

[67] *See* Miranda Willson, Heather Richards, Brian Dabbs, *Biden regulatory plan set to shake up energy sector,* Energywire, Dec. 7, 2023 (''The White House released a regulatory plan Wednesday that could shape President Joe Biden's energy legacy . . . . *[T]wo of the Federal Energy Regulatory Commission's most high-profile proposed transmission rules are listed on the [White House] agenda* . . . . One of those FERC rules would *change how large electric power lines are planned and paid for* . . . .'') (emphases added), *https://www.eenews.net/articles/biden-regulatory-plan-set-to-shake-up-energy-sector/; see also supra* nn.5, 8, 10, 13, 15, 16.

[68] In the very recent past, this Commission stood up for its independence despite intense pressure from a presidential administration. *See, e.g.,* Steven Mufson, *Trump-appointed regulators reject plan to rescue coal and nuclear plants,* The Washington Post, Jan. 8, 2018 (explaining that ''[t]he independent five-member commission [that rejected the president's proposal] includes four people appointed by President Trump''), *https://www.washingtonpost.com/news/energy-environment/wp/2018/01/08/trump-appointed-regulators-reject-plan-to-rescue-coal-and-nuclear-plants/.*

rule is fundamentally different in numerous ways, yet these fundamental changes were never put out for additional public comment.[69] These fundamental changes include, but are not limited to, the following:

24. *The Final Rule Imposes Preferential Policy and Corporate-Driven Project Costs on Consumers in Non-Consenting States:* Contrary to the NOPR, the final rule requires the filing of one or more *ex ante* cost allocation methods to apply to selected Long-Term Regional Transmission Facilities, setting up a mechanism to impose a regional cost allocation for preferential policy and corporate-driven projects when states do not consent, either by approving a cost allocation proposed by transmission owners, by RTOs, or one directly imposed by the Commission itself.[70] This is a fundamental change from the NOPR.

25. *The Final Rule Mandates Planning Criteria and Purported Benefits:* Contrary to the NOPR, the final rule mandates a specific set of planning criteria, and specifically purported benefits, that must be used by transmission providers for these preferential policy and corporate-driven projects.[71] Mandating the planning criteria and benefits is simply a way of ''pre-cooking'' outcomes and is directly contrary to the NOPR's explicit language that said it was *not* mandating outcomes, only a planning process.[72] This is a fundamental change from the NOPR.

26. *The Final Rule Abandons Regional Cost Allocation Principle (6):* Contrary to the NOPR,[73] the final rule abandons the regional cost allocation principle [74] that would allow a transmission planning region to use different cost allocation methods for different types of facilities in a regional transmission plan. The final rule replaces this flexibility with a one-size-fits-all model.[75] This is a fundamental change from the NOPR.

27. *The Final Rule Effectively Eliminates a Voluntary State Agreement Process:* Contrary to the NOPR, the final rule effectively eliminates the use of a voluntary State Agreement Process, such as the one that has been used by PJM since Order No. 1000.[76] Not only is this directly contrary to comments filed by state regulators,[77] but it represents a fundamental change from the NOPR.

28. *The Final Rule Leaves the CWIP Incentive Intact:* Contrary to the NOPR, the final rule walks back the proposal not to allow use of the CWIP incentive.[78] This NOPR provision was one of the strongest consumer protection features.[79] Instead, the Commission leaves the CWIP incentive intact and that consumer protection has been removed. This is a fundamental change from the NOPR.

29. *The Final Rule Makes Local Transmission Planning Less Transparent:* Contrary to the NOPR,[80] the final rule makes fundamental changes to the NOPR's section on Local Transmission Planning.[81] Local Transmission Planning disclosure and transparency requirements no longer apply to asset management projects. This is a fundamental change from the NOPR.

III. The Final Rule Exceeds FERC's Authority Under the FPA

30. The final rule's determination that its reforms are within the Commission's legal authority under section 206 is flat wrong.[82] The final rule is just a pretext for enacting the current presidential administration's ''net zero 2035'' policy agenda, as well as that of large corporate buyers of preferential power and other special interests.[83] As such, the final rule goes far beyond the scope of Order No. 1000, as affirmed by *South Carolina,*[84] and exceeds FERC's authority under the FPA. Specifically, the final rule requires transmission providers to incorporate into their transmission planning seven categories of factors and a set of seven required benefits to drive the construction of projects to achieve the final rule's preferred substantive outcomes: namely, the development and purchase of certain preferred generation resources. In so doing, the final rule seeks to recast FERC as a national IRP planner with extraordinary powers to oversee and dictate to all public utility transmission providers in the country, in RTO and non-RTO regions, detailed instructions on planning transmission that fulfills the current administration's preferred policies as to the types of generation it wants to build, and to charge consumers trillions of dollars for this transmission. This transformation of FERC into a national IRP planner violates FPA section 201 by infringing on the authority of the states, and it reflects a tremendous expansion of the agency's power not permitted under the major questions doctrine.

A. South Carolina Does Not Provide a Legal Justification for the Commission's Actions in the Final Rule

31. In arguing that the Commission is acting within its legal authority under section 206 to adopt its reforms for Long-Term Regional Transmission Planning, today's final rule heavily relies on *South Carolina.*[85] However, given the significant differences between Order No. 1000 and the final rule, that reliance is grossly misplaced.

32. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the Commission's *pro forma* open access transmission tariff could support the development of more efficient or cost-effective transmission facilities.[86] Such reforms included, *inter alia,* the requirement for transmission providers to participate in regional planning processes; the requirement that such regional transmission planning processes must consider transmission needs that are driven by public policy requirements; and the requirement that transmission providers develop a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, with such method having to satisfy six regional cost allocation principles.

33. But Order No. 1000 was built on what may be a foundation of sand known as ''*Chevron* deference.'' As the D.C. Circuit explained in *South Carolina,* ''[t]he court reviews challenges to the Commission's interpretation of the FPA under the familiar two-step framework of [*Chevron*].'' [87] The D.C. Circuit further explained that, ''[i]f the court determines 'Congress has directly spoken to the precise question at issue,' and 'the intent of Congress is clear, that is the end of the matter.' '' [88] This is often referred to as ''*Chevron* step one.'' [89] The court stated, in contrast, that ''[i]f . . . 'the statute is silent or ambiguous with respect to the specific issue,' then the court must determine 'whether the agency's answer is based on a permissible construction of the statute.' '' [90] This is often referred to as ''*Chevron* step two.'' [91] The D.C. Circuit explained that ''*Chevron* step two . . . requires [the court] to uphold an agency's reasonable interpretation of a statute it administers.'' [92] That is, the court applies *Chevron* deference.[93]

34. In *South Carolina,* the D.C. Circuit applied *Chevron* deference to the Commission's interpretation of FPA section 206 in affirming many aspects of Order No.

[69] The process leading to the adoption of Order No. 1000, the final rule's direct predecessor but one not nearly as sweeping in its application, was described in paragraphs 22 through 24 of that order. Order No. 1000, 136 FERC ¶ 61,051 at PP 22–24.

[70] Final Rule, 187 FERC ¶ 61,068 at PP 1291–1292.

[71] *Id.* PP 3, 269, 719–720.

[72] *See* NOPR, 179 FERC ¶ 61,028 at PP 9, 245.

[73] *See id.* P 302.

[74] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 685.

[75] Final Rule, 187 FERC ¶ 61,068 at P 1469 (''[U]nlike under Order No. 1000, transmission providers *cannot* adopt different Long-Term Regional Transmission Cost [A]llocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.'') (emphasis added); *see also id.* P 1474.

[76] *See, e.g., id.* PP 1291–1292. A more detailed discussion on how the final rule effectively guts the State Agreement Process is in *infra* Section IV.B.1.b.

[77] *See* Final Rule, 187 FERC ¶ 61,068 at P 1323 (citations omitted).

[78] *Id.* P 1547.

[79] *See* NOPR, 179 FERC ¶ 61,028 at P 333; NOPR Concurrence at P 15.

[80] *See* NOPR, 179 FERC ¶ 61,028 at PP 400–413.

[81] Final Rule, 187 FERC ¶ 61,068 at P 1625.

[82] *See id.* PP 86, 253.

[83] *See supra* Section I.

[84] 762 F.3d 41.

[85] *E.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 86, 253, 256 & n.604, 257 & n.605, 277.

[86] *Id.* P 16 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3).

[87] *South Carolina,* 762 F.3d at 54 (citing *Chevron,* 467 U.S. 837).

[88] *Id.* (quoting *Chevron,* 467 U.S. at 842).

[89] *See, e.g., id.* at 84.

[90] *Id.* at 54 (quoting *Chevron,* 467 U.S. at 843).

[91] *See, e.g., id.* at 58–59 (citing *Chevron,* 467 U.S. at 843), 84.

[92] *Id.* at 76 (citing *Nat'l Cable & Telecomms. Ass'n* v. *Brand X internet Servs.,* 545 U.S. 967, 982 (2005)).

[93] Note, however, that the U.S. Supreme Court is revisiting the 40-year-old doctrine and has indicated that it may narrow or overturn it in the pending cases, *Loper Bright Enterprises* v. *Raimondo,* No. 22–451 (argued Jan. 17, 2024) and *Relentless* v. *Dep't of Commerce,* No. 22–1219 (argued Jan. 17, 2024).

1000, including its planning mandates.[94] In affirming the planning mandates, the court emphasized that Order No. 1000 focused on process and *not* substantive outcomes:

In Order No. 1000, the Commission expressly ''decline[d] to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan.'' More generally, the Commission disavowed that it was purporting to ''determine what needs to be built, where it needs to be built, and who needs to build it.'' As the Commission explained on rehearing, ''*Order No. 1000's transmission planning reforms are concerned with process*'' *and* ''*are not intended to dictate substantive outcomes.*'' *The substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities remain within the discretion of the decision-makers in each planning region.*[95]

35. Similarly, in determining that Order No. 1000's public policy mandate fell within the Commission's authority under section 206, the D.C. Circuit noted the mandate did not promote any particular public policy:

[Petitioners] seem to argue that the Commission can only exercise authority to promote goals specified in the FPA and that the public policy mandate cannot be justified with respect to any of those goals. This argument misunderstands the nature of the mandate. *It does not promote any particular public policy* or even the public welfare generally. The mandate simply recognizes that state and federal policies might affect the transmission market and directs transmission providers to consider that impact in their planning decisions. . . . This fits comfortably within the Commission's authority under Section 206. . . . [T]he public policy mandate bears directly on the provision of transmission service.[96]

Just as with Order No. 1000's planning mandates, the court again emphasized Order No. 1000's public policy mandate required the establishment of processes:

But petitioners' attack is once again based on a misunderstanding of the orders. The orders merely require regions to establish *processes* for identifying and evaluating public policies that might affect transmission needs. The regions are free to choose their own manner of determining how best to identify and accommodate these policies.[97]

36. Finally, in affirming Order No. 1000's requirements pertaining to cost allocation, the court again applied *Chevron* deference to its interpretation of section 206.[98] The court noted that Order No. 1000 used a ''light touch'' in its cost allocation reforms:

In keeping with the overall approach of the transmission planning reforms, [Order No. 1000] uses a light touch: it does not dictate how costs are to be allocated. Rather, [Order No. 1000] provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes.[99]

37. While Order No. 1000 used a ''light touch,'' this pretextual final rule is heavy handed. To ensure that policy and corporate-driven projects are ultimately built so that the preferred generation is built, the final rule seeks to promote particular public policies and to dictate substantive outcomes through its reforms to the Commission's transmission planning and cost allocation processes.[100] If Order No. 1000 was upheld precisely because it was only mandating *processes,* not *outcomes,* then this final rule cannot stand on *South Carolina* because it nakedly intends to produce very specific outcomes.

38. How does it intend to do this? First, in contrast to Order No. 1000, which mandated consideration of public policies in transmission planning but *not* a particular policy,[101] the final rule *requires* transmission providers in their Long-Term Regional Transmission Planning to incorporate seven categories of factors—*i.e.,* specific policies, as I have emphasized. Most of these mandatory categories of factors, which drive long-term transmission planning, specifically relate to the development and purchase of ''green energy,'' including, *inter alia:* (i) *state and local laws affecting the resource mix,* (ii) state and local laws on *decarbonization,* (iii) generator interconnection requests and withdrawals,[102] and (iv) *corporate,* state and local government commitments to *purchase* ''*green energy.*''

39. The final rule describes the relationship between the categories of factors, transmission needs, and benefits, among other terms:

For purposes of this final rule, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

For purposes of this final rule, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning, which, as discussed in this final rule, includes running scenarios and *considering the enumerated categories of factors.*[103]

Thus, categories of factors clearly shape the identification of transmission needs. Demonstrating this causal relationship, the final rule explains that ''best available data inputs are data inputs that . . . reflect the *list of factors* that transmission providers account for in their Long-Term Scenarios,'' [104] and, in turn, ''Long-Term Scenarios . . . incorporate various assumptions using best available data inputs about the future electric power system . . . *to identify Long-Term Transmission Needs* and enable the identification and evaluation of transmission facilities to meet such transmission needs.'' [105]

40. And, as we know, the identification of needs leads to the identification of transmission facilities that meet such needs; the identification of transmission facilities in turn leads to the measure of the benefits associated with those facilities; and the measure of benefits informs the evaluation of those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation. Thus, as the categories of factors are slanted toward transmission to facilitate preferred generation, the resulting output of the transmission planning process will inevitably have a similar bent. In other words, the final rule's mandate of the categories of factors starts the domino effect toward the final rule's agenda, an agenda that goes far beyond Order No. 1000.

41. Second, in contrast to Order No. 1000, whose reforms ''[were] concerned with process'' and ''[were] not intended to dictate substantive outcomes,'' [106] the final rule requires transmission providers to measure a set of seven required benefits in their long-term transmission planning so that the pretextual agenda will be realized. By mandating minimum benefits that the transmission providers must use to evaluate potential transmission facilities,[107] the final rule is doing the opposite of using a ''light touch;'' rather, the final rule is putting its thumb on the scale, seeking to dictate outcomes of the transmission planning process. As I must continue to emphasize, by mandating benefits, the final rule makes consumers into involuntary ''beneficiaries,'' who, through regional cost allocation, will be forced to pay for transmission projects that support the development and purchase of preferential power. Accordingly, as with the final rule's mandated categories of factors, the mandatory minimum benefits serve to advance the final rule's specific policy objectives regarding the resource mix. Such favoritism is blatantly unduly discriminatory and preferential in contravention of section 206, and therefore, the final rule is, simply put, not entitled to *Chevron* deference in any form.

B. The Final Rule Violates FPA Section 201

42. The final rule also infringes on the states' authority over electric generation reserved to them by FPA section 201 and is thus *ultra vires.*

43. As relevant here, FPA section 201(b) provides:

[94] *See South Carolina,* 762 F.3d at 56–59 (internal citations omitted).

[95] *Id.* at 57–58 (emphasis added; internal citations omitted).

[96] *Id.* at 89–90 (citation omitted).

[97] *Id.* at 91 (emphasis in original; internal citations omitted).

[98] *Id.* at 84–86.

[99] *Id.* at 81.

[100] In so doing, the final rule violates section 201 as well. *See infra* Section III.B.

[101] *See South Carolina,* 762 F.3d at 89–90.

[102] This factor category is another way to subsidize and prefer wind and solar developers, which dominate the interconnection queues.

[103] Final Rule, 187 FERC ¶ 61,068 at PP 38–39 (emphasis added).

[104] *Id.* PP 42, 633 (emphasis added).

[105] *Id.* PP 40 and 302 (emphasis added).

[106] *See South Carolina,* 762 F.3d at 58 (internal citation omitted).

[107] Final Rule, 187 FERC ¶ 61,068 at P 965.

The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction,* except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[108]

Further, section 201(a) also specifies that ''such Federal regulation . . . extend[s] only to those matters which are not subject to regulation by the States.'' Courts have found that ''states have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable generation.'' [109] These powers are reserved to the states under section 201.

44. In *South Carolina,* the D.C. Circuit rejected the argument that section 201 prohibited Order No. 1000's transmission planning mandate.[110] The D.C. Circuit emphasized that ''because the planning mandate relates wholly to electricity transmission, *as opposed to electricity sales,* it involves a subject matter over which the Commission has relatively broader authority.'' [111] The court also reasoned that ''because [Order No. 1000's] planning mandate is directed at ensuring the proper functioning of the interconnected grid spanning state lines, . . . the mandate fits comfortably within Section 201(b)'s grant of jurisdiction over 'the transmission of electric energy in interstate commerce.' '' [112] The court thus concluded that ''Section 201 [did] not preclude the Commission's regulation of transmission planning in [Order No. 1000]'' and that Order No. 1000 ''[did] not interfere with the traditional state authority that is preserved by Section 201.'' [113]

45. However, in contrast to Order No. 1000, the final rule absolutely does ''interfere with the traditional state authority that is preserved by Section 201'' to ensure that its preferential policy and corporate-driven projects get built. By mandating, *inter alia,* categories of factors that drive the transmission planning process and by mandating minimum benefits to be used in the evaluation of potential Long-Term Regional Transmission Facilities, the final rule seeks to spur the building of transmission so as to promote a specific policy objective: the development and purchase of preferential generation. Accordingly, although the final rule strenuously insists that it is not mandating *outcomes,*[114] it is doing so by manipulating the *inputs* of transmission planning (*i.e.,* ''pre-cooking'').[115] In other words, the final rule seeks to do indirectly what it may not do directly.

46. As I explained in my concurrence to the NOPR:

States can prefer, mandate or subsidize specific types of generation resources, but the Commission cannot use its authority over transmission to pressure, steer or require regional planning entities to act as the Commission's agents and do indirectly what the Commission cannot do directly. The Commission is not a national integrated resource planner. Order No. 1000, to its credit, recognized this clear delineation between federal and state authority.[116]

I also explained that ''the Commission cannot *impose* a preference for certain types of generation *nor require* regional entities to plan transmission designed to prefer or facilitate one type of generation over another.'' [117]

47. The text of the FPA gives this Commission *no* authority whatsoever to act as a national IRP planner for the purpose of promoting its preferred generation resource mix. Pulling back the curtain, that is exactly what this pretextual final rule seeks to do. By extending FERC's control over every public utility transmission planner in the country, RTO or non-RTO, and ordering them to plan transmission lines intended to advance preferred policy and corporate goals, the Commission is stepping into the role of national IRP planner. FERC's authority under the FPA is limited to matters that *directly* affect *rates,* not practices that may theoretically have some tangential, indirect effect on rates,[118] especially improper purposes such as ordering transmission planning to promote one or more states' public policies or corporate goals as to preferred generation resources. Congress intended FERC to be a rate regulator, not a planner of generation *or transmission designed to bring about the construction of preferred types of generation.* Indeed, FPA section 215 explicitly states that FERC may *not* order the construction of any generation or transmission asset.[119] FERC cannot order transmission providers to do what FERC itself has no authority to do, yet that is exactly what this final rule aims to do.

48. The final rule purports to order transmission planners to plan for a ''predicted'' generation mix in a distant future 20 years away, but the exact generation mix in 20 years is impossible to predict.[120] The real goal of this pretextual final rule is not to try the impossible by predicting the generation mix in 20 years. Instead, the final rule is an attempt to become a national IRP planner and *bring about* a preferred generation mix through transmission planning by manipulating and shaping the future generation mix the special interests supporting this final rule want now.

49. The final rule denies that it is infringing on state authority reserved under FPA section 201, arguing, *inter alia,* that it directly regulates only those practices that affect the rates for the transmission of electric energy in interstate commerce and that it is not aiming to indirectly regulate any matter reserved to the states by FPA section 201.[121]

[108] 16 U.S.C. 824(b)(1) (emphases added).

[109] *See, e.g., Entergy Nuclear Vt. Yankee, LLC* v. *Shumlin,* 733 F.3d at 417 (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.,* 71 FERC at 62,080).

[110] 762 F.3d at 62–64.

[111] *Id.* at 63 (emphasis added) (footnote omitted)

[112] *Id.* (internal citations omitted).

[113] *Id.* at 64.

[114] *See* Final Rule, 187 FERC ¶ 61,068 at PP 954–955, 1026–1028.

[115] *Id.* P 965.

[116] NOPR Concurrence at P 2; *see also id.* n.4 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 154 (''*[T]he regional transmission planning process is not the vehicle by which integrated resource planning is conducted;* that may be a separate obligation imposed on many public utility transmission providers and *under the purview of the states.*'') (emphases added in NOPR Concurrence)).

[117] *Id.* P 12 (emphases in original).

[118] *See, e.g., CAISO* v. *FERC,* 372 F.3d at 400 (holding that FERC cannot prescribe the membership of the CAISO board, as FERC has authority over only ''rates, charges, classifications, and closely related matters''); *see also Ari Peskoe, Replacing the Utility Transmission Syndicate's Control,* Energy Law Journal, Vol. 44.3 547, 578 (2023) (Peskoe Article) (''FERC's authority over utility 'practices' is best understood as referring to 'actions habitually being taken by a utility in connection with a rate found to be unjust and unreasonable.''') (footnote omitted), *https://www.eba-net.org/wp-content/uploads/2023/11/8-Peskoe547-618.pdf.*

[119] FERC regulates RTOs and RTO markets to ensure just and reasonable rates to consumers, but FERC has no authority to order a load-serving public utility to build a specific generation facility, only states can. *See* 16 U.S.C. 824(b)(1); *see also Hughes* v. *Talen Energy Mktg.,* 578 U.S. 150, 154 (2016) (''The States' reserved authority includes control over in-state 'facilities used for the generation of electric energy.''' (quoting 16 U.S.C. 824(b)(1))); *see also* 16 U.S.C. 824o(i)(2) (''[Section 215 of the FPA] does not authorize the [Electric Reliability Organization, *i.e.,* NERC] or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or service.''). Congress recently gave FERC a narrowly limited form of ''backstop'' siting authority for certain designated transmission lines, but that authority is not implicated in this final rule.

[120] PATH Concurrence at P 4 (''PATH graphically illustrates the inherent dangers in approving for regional cost allocation long-distance projects based on a prediction (*i.e.,* a guess) of what the generation mix will be in 20 years or more. PATH was originally part of the huge ''Project Mountaineer'' scheme—announced with great fanfare right here at the Commission itself—to build *three* high-voltage lines across hundreds of miles from West Virginia to East Coast load centers. The vast majority of the power to be delivered along these lines was to be *coal*-generated. After running into a firestorm of opposition in both the states in the path (no pun intended), as well as the end-user load states, Project Mountaineer was abandoned except for the PATH project, which represented a segment of one of the proposed Project Mountaineer lines. That segment was never built either. Yet, consumers have been paying for it ever since. The lesson here is clear: For policy-driven long-distance, regional transmission projects affecting consumers in multiple states, it is absolutely essential that state regulators have the authority to approve—or disapprove—the construction of these lines *and* how they are selected for regional cost allocation *and* what that cost allocation formula is, if their consumers are going to be hit with the costs.'') (emphasis in original).

[121] Final Rule, 187 FERC ¶ 61,068 at P 263; *see also, e.g., id.* P 271 (''[T]he requirements in this final rule respect and do not unlawfully infringe on state authority. Rather . . . the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes.'').

The final rule is chock-full of ''nothing to see here'' rhetoric asserting that it does not seek to shape the generation resource mix, but merely responds to changes in the electric industry.[122] ''Pay no attention to the [agenda] behind the [green] curtain! '' [123] the final rule insists across 1300 pages. But it should be obvious by now that the final rule is just a pretext for enacting this administration's ''net zero 2035'' policy agenda, as well those of corporate and other special interests.[124] The true intent of the final rule is revealed by mandated categories of factors and minimum benefits, which drive the transmission development necessary to achieve the final rule's preferred generation resource mix. Any honest account of the final rule cannot ignore the monetary windfall it would shower on generation and transmission developers; it is no wonder, therefore, why they were among the strongest supporters for the final rule. Nor can any rational individual—unless living in the Land of Oz—reasonably deny the role the final rule plays in furthering this pretextual agenda.[125] In light of this backdrop, the final rule's repeated assertions that it does not seek to shape the country's resource mix are simply not credible. Contrary to the final rule's claims, in violation of FPA section 201, the final rule transforms the Commission into a national IRP planner to promote the construction of transmission lines to further the development of the final rule's preferred generation resources.

C. The Final Rule Violates the Major Questions Doctrine

50. Courts generally look with suspicion on ''cryptic'' delegations of authority,[126] and they are generally skeptical of agencies that seek to find ''elephants in mouseholes,'' or otherwise seek to rely on tiny grants of authority to justify major actions.[127] As the Supreme Court explained in *West Virginia* v. *EPA:*

Where the statute at issue is one that confers authority upon an administrative agency, that inquiry must be ''shaped, at least in some measure, by the nature of the question presented''—whether Congress in fact meant to confer the power the agency has asserted. In the ordinary case, that context has no great effect on the appropriate analysis. Nonetheless, our precedent teaches that there are ''extraordinary cases'' that call for a different approach—cases in which the ''history and the breadth of the authority that [the agency] has asserted,'' and the ''economic and political significance'' of that assertion, provide a ''reason to hesitate before concluding that Congress'' meant to confer such authority.[128]

51. I invoked the major questions doctrine in my dissent to the proposed changes to the Commission's certificate policy, even before *West Virgina* v. *EPA* was handed down. In my dissent, I wrote that:

''The federal government's powers . . . are not general[ ] but limited and divided. Not only must the federal government properly invoke a constitutionally enumerated source of authority to regulate in this area or any other, it must also act consistently with the Constitution's separation of powers. And when it comes to that obligation, this Court has established at least one firm rule: 'We expect Congress to speak clearly' if it wishes to assign to an executive agency decisions 'of vast economic and political significance.' We sometimes call this the major questions doctrine.''

In short, the major questions doctrine presumes that Congress reserves major issues to itself, so unless a grant of authority to address a major issue is explicit in a statute administered by an agency, it cannot be inferred to have been granted.

* * * * *

Yet the Supreme Court has made it clear that broad deference to administrative agencies on major questions of public policy is not in order when statutes are lacking in any explicit statutory grant of authority. ''*When much is sought from a statute, much must be shown.* . . . [B]road assertions of administrative power demand *unmistakable legislative* support.'' [129]

52. The final rule's actions clearly implicate the major questions doctrine. If imposing a final rule intended to cost consumers literally trillions of dollars to build transmission projects designed to implement a sweeping policy agenda never passed by Congress is *not* a major question of public policy, then there is no such thing.[130]

53. Yet the final rule brushes aside arguments that it would not withstand scrutiny under the major questions doctrine.[131] Against these arguments, the final rule denies that its aim is to influence the generation mix; [132] asserts that it ''neither transforms nor expands the Commission's authority; it merely applies existing authority;'' [133] asserts that ''the differences in transmission planning required by this final rule represent differences in degree, not kind, from the Commission's longstanding regulations;'' [134] and asserts that its ''incremental process improvements [from Order No. 1000], while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the 'vast economic and political significance' that would implicate the major questions doctrine.'' [135] None of these assertions are credible.

54. This final rule violates the major questions doctrine. As discussed above, it is axiomatic that Congress has not intended for the Commission to be a national IRP planner. On the contrary, it has left both the siting of transmission and the development of generation to the states.[136] Yet the final rule encroaches on these traditional state prerogatives in the absence of any explicit Congressional authorization to do so.

55. The final rule seeks to shape specific policy outcomes by mandating categories of factors and minimum benefits. In addition, the final rule does something else that also arguably makes it transformative. Citing, *inter alia, South Carolina,* the final rule declares that the Commission has exclusive jurisdiction over regional transmission planning and cost allocation processes:

As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's *exclusive* jurisdiction.[137]

In fact, the *South Carolina* court did *not* state that the Commission has *exclusive* jurisdiction over regional transmission planning and cost allocation. In fact, that court noted, for example, that the Florida Public Service Commission is statutorily vested with authority to ''plan[], develop[ ], and main[tain] . . . a coordinated electric power grid'' throughout the state.[138]

56. Whether the Commission can exclusively supplant the states in transmission planning and cost allocation is a major question—particularly considering the enormous breadth of the transmission

[122] *E.g., id.* PP 129, 130, 254, 259–263, 266, 271, 275.

[123] You can decide for yourself whether the ''green curtain'' represents ''green energy'' or something else that's green.

[124] *See supra* Sections I, III.B.

[125] *See supra* nn.5, 8, 10, 13, 15, 16, 67.

[126] *See FDA* v. *Brown & Williamson Tobacco Corp.,* 529 U.S. 120, 160 (2000).

[127] *See West Virginia* v. *EPA,* 597 U.S. at 746–47 (Gorsuch, J., concurring) (quoting *Whitman* v. *Am. Trucking Ass'ns,* 531 U.S. 457, 468 (2001)).

[128] *Id.* at 700 (internal citations omitted).

[129] *Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,107 (2022) (Christie, Comm'r, dissenting at P 22–23 (quoting *Nat'l Fed'n of Indep. Bus.* v. *Dep't of Labor, OSHA,* 595 U.S. 109, 121–22 (2022) (Gorsuch, J., concurring); *In re MCP No. 165,* 20 F.4th 264, 267–68 (6th Cir. 2021) (Sutton, C.J., dissenting (emphases added))) (internal citations omitted) (Certificate Dissent), *https://www.ferc.gov/news-events/news/items-c-1-and-c-2-commissioner-christies-dissent-certificate-policy-and-interim.*

[130] *See* Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines,* The New York Times, Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, '' 'I've called [the final] rule the *biggest energy policy in the country.'* '' (emphasis added)), *https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html.*

[131] Final Rule, 187 FERC ¶ 61,068 at P 275.

[132] *Id.*

[133] *Id.* P 277.

[134] *Id.*

[135] *Id.* P 278 (quoting *West Virginia* v. *EPA,* 597 U.S. at 735 (J. Gorsuch, concurring)).

[136] *See supra* Section III.B. Since 2005, FERC has had very limited backstop siting authority for certain transmission projects that has never been used. *See generally Applications for Permits to Site Interstate Elec. Transmission Facilities,* Order No. 1977, 187 FERC ¶ 61,069 (2024).

[137] Final Rule, 187 FERC ¶ 61,068 at P 86 & n.184 (emphasis added) (citing *South Carolina,* 762 F.3d at 55–59, 84 (affirming the Commission's authority to regulate transmission planning and cost allocation as practices affecting rates); Order No. 1000–A, 139 FERC ¶ 61,132 at P 577 (holding that ''requirements regarding transmission planning and cost allocation . . . are practices affecting rates.'')); *see also id.* P 130 (''Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity *are the exclusive jurisdiction of the Commission,* we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential.'') (emphasis added); *id.* P 770.

[138] *See, e.g., South Carolina,* 762 F.3d at 62 n.3.

grid, the importance of electricity in everyday life, and the trillions of dollars in transmission investment (read, cost increases) this final rule intends to impose on consumers.[139] The final rule's conclusion that regional transmission planning and cost allocation processes are subject to the Commission's exclusive jurisdiction suggests that the Commission ''occupies the field'' [140] in these areas.[141] But this is wrong. This pretextual final rule erodes the states' authority, which is inconsistent with the principle of cooperative federalism reflected in the FPA. Under the major questions doctrine, absent an act of Congress, the Commission may not usurp the powers of the states in this manner.

IV. The Final Rule Fails Under Both Prongs of FPA Section 206

57. I cannot support the final rule because it has been fundamentally changed from the NOPR. In jettisoning essential components of the NOPR, the final rule has been reduced to a mere pretext for this supposedly *independent* Commission's effort to implement the current administration's ''net zero 2035'' policies. It will not produce rates that are just and reasonable and not unduly discriminatory or preferential. This final rule does not satisfy either of the requirements of FPA section 206. Under section 206, the Commission must first find that the rate on file is no longer just and reasonable and not unduly discriminatory or preferential. Then the Commission must find that a particular replacement rate would be just and reasonable and not unduly discriminatory or preferential.[142] The final rule fails on both counts.

58. Although the current regional transmission planning processes could be improved—they are certainly not in need of the final rule's *solutions.* Even if these solutions were the only way forward to reform regional transmission planning, an act of Congress would be necessary first because the final rule is far beyond the reach of the FPA. While the Commission might *prefer* a different rate, that preference alone does not make all the filed rates of every transmission provider unjust and unreasonable.

A. The Final Rule Fails To Justify Its Action Under Section 206

59. The final rule presents no justification for taking action *in this proceeding* against *all* of the filed transmission rates pursuant to FPA section 206. The record, while consisting of thousands of pages of comments, simply does not contain substantial evidence sufficient to make a generic showing that the existing filed rates of all transmission providers are unjust, unreasonable, unduly discriminatory or preferential.[143] In *South Carolina,* the D.C. Circuit explained that ''the substantial evidence test'' for a rulemaking proceeding '' 'requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.' '' [144] Here, the final rule's ''rel[iance] on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution'' [145] fails because it relies on cherry-picked special interest comments to support the pre-baked and pretextual findings needed to enact the administration's preferential, and *discriminatory,* policy agenda as well those of corporate and other special interests.

1. *The Record Is Not Sufficient to Make a Generic Showing That Every Transmission Providers' Regional Transmission Planning and Cost Allocation Processes Are Unjust, Unreasonable, and Unduly Discriminatory or Preferential*

60. The evidence in the record that is used to support the final rule's section 206 finding consists largely of comments from special interests that will profit from the final rule. The final rule also signals that there has been limited regional transmission development since Order No. 1000. This evidence should not be used to mean that every transmission provider in the country has transmission practices that are unjust and unreasonable.

61. The final rule declines to analyze the ''justness and reasonableness of either generator interconnection processes or local transmission planning processes'' in its survey of issues in regional transmission planning.[146] The final rule identifies benefits of transmission planning.[147] The final rule states that ''transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints.'' [148] The final rule states that transmission spending has increased, which turns into higher customer bills.[149] The final rule identifies projections are necessary for growing future transmission needs, including load growth [150] and changing reliability needs.[151] And supply is changing due to state policies, customer preferences, and utility preferences (the latter two can also be driven by state policies or by activist investor preferences).[152]

62. Translating FERC-speak, we are left with bland statements of the obvious: Transmission is expensive to build; transmission spending is up; generators front a lot of the needed money; consumers eventually pay them back; lack of regional integrated planning results in piecemeal transmission construction; this is inefficient and costs consumers more. Yet simply because a rate could be more efficient, that alone is not enough to make the filed rate unjust and unreasonable.

63. Many of the special interest commenters point to studies, projections, and reports that show that regional transmission planning could be done more efficiently.[153] When we peel back the ''green curtain'' shrouding this final rule, however, we see that these comments are almost exclusively from self-interested entities which would gain substantially from the very Commission action that they support.[154] Indeed, the record being used to support the section 206 finding consists of special interests who are going to profit monetarily from the final rule, including generation developers, transmission developers, and corporate purchasers of preferred power.[155] None of these comments (individually or taken together) are sufficient to meet the high burden of proof that all transmission providers' tariffs are unjust and unreasonable due to the profit-seeking motivations behind them.

64. In addition, the final rule looks back over the period following Order No. 1000 and states that regional transmission planning processes have yielded only ''limited investments in regional transmission planning projects.'' [156] Let's suppose that over the last decade a transmission developer had instead proposed massively expanding transmission while the load growth projections remained flat. Consumers commenting on that aggressive plan would have challenged it as gold-plating. Regulators

[139] *See FERC* v. *Elec. Power Supply Ass'n,* 577 U.S. 260, 281 (2016) (''It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level.'').

[140] *See Silkwood* v. *Kerr-McGee Corp.,* 464 U.S. 238, 248 (1984) (''If Congress evidences an intent to occupy a given field, any state law falling within that field is preempted.'' (citation omitted)); *PPL EnergyPlus, LLC* v. *Nazarian,* 753 F.3d 467, 475–476 (4th Cir. 2014) (''Even where state regulation operates within its own field, it may not intrude indirectly on areas of exclusive federal authority.'' (quoting *Pub. Utils. Comm'n of State of Cal.* v. *FERC,* 900 F.2d 269, 274 n.2 (D.C. Cir.1990) (internal quotation marks omitted))).

[141] The final rule's determination here aligns with the final rule's complete gutting of the roles of the states in transmission planning and cost allocation. *See infra* Section IV.B.1.

[142] 16 U.S.C. 824e.

[143] *See South Carolina,* 762 F.3d at 64–65 (citations omitted).

[144] *Id.* at 54 (quoting *Wis. Gas Co.* v. *FERC,* 770 F.2d 1114, 1156) (alterations in the original)).

[145] *See* Final Rule, 187 FERC ¶ 61,068 at P 132 (citing *South Carolina,* 762 F.3d at 67) (additional citation omitted).

[146] *Id.* P 111.

[147] *Id.* PP 90–91.

[148] *Id.* P 90.

[149] *Id.* P 92.

[150] *Id.* P 95.

[151] *Id.* PP 93–94.

[152] *Id.* PP 96–97.

[153] *See, e.g.,* Johannes Pfeifenberger, et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 48–49 (Oct. 2021), *https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf*; Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* at 26–28 (Jan. 2021), *https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf*; Johannes P. Pfeifenberger, et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* (Apr. 2019), *https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf.*

[154] Such commenters include ACORE, PIOs, ACEG, Advanced Energy Buyers, AEE, Renewable Northwest, SREA, and Clean Energy Buyers.

[155] *See* Final Rule, 187 FERC ¶ 61,068 at P 96.

[156] *Id.* P 101.

would have rejected it as imprudent. The so-called ''limited investments'' were instead a sign of responsiveness to projections made during that era. Rather than seeing this outcome as a feature of considered ratemaking during a period of low load growth, the final rule attributes this lack of investment to the shortcomings of the existing regional transmission planning processes—meaning the tariff changes mandated by Order No. 1000.[157] For these reasons, the final rule's reliance on a lack of regional transmission development post-Order No. 1000 is not persuasive, especially to support the finding that all transmission providers' tariffs are unjust and unreasonable.

2. The Record Shows That Regional Planning Deficiencies Exist *Only* in Isolated Pockets

65. The evidence in this record does not demonstrate a single nationwide systemic problem. Rather, the record shows that the ''deficiencies identified by the Commission 'exist[ ] only in isolated pockets.' '' [158] The final rule even recognizes the many regions representing a substantial percentage of consumers where regional transmission planning is working.[159] The final rule points to the MISO Multi-Value Project transmission planning process as an effective example of regional transmission planning.[160] From this, it could be concluded that the final rule suggests that regional transmission planning is working in MISO, including on a long-term basis. It is logical to conclude similarly regarding CAISO's [161] and New York's regional transmission planning.[162] Vertically integrated monopoly public utilities have expanded their transmission capacity by engaging in integrated resource planning that is reviewed and approved by their state regulators.[163] NRECA, an organization representing both transmission providers and transmission-dependent entities, highlights that its members have observed regional transmission planning processes that range from successful to broken.[164] According to NRECA, some RTO regions are working, and others are not. NRECA similarly states that some non-RTO regions are working, and others are not.

66. This is hardly ironclad evidence sufficient to support a generic finding that the regional transmission planning processes are no longer just and reasonable. The record here shows that regional and multistate regional planning is happening in significant and large swaths of the country subject to our rate jurisdiction, including on longer-term horizons, and that other regions have room for improvement. These circumstances are entirely different than those facing the Commission when it issued Order No. 1000. The factual justification for a single, national FPA section 206 finding is simply not present in the way it was for Order No. 1000. No amount of hand waving or misdirection can change the lack of sufficient evidentiary support for this Commission to take the sweeping national action pursuant to FPA section 206 in this rule. This significant deficiency leaves this *entire* exercise open to meaningful challenge.

B. The Replacement Rate Is Not Just and Reasonable

67. Not only does the final rule fail to meet its evidentiary burden, but the replacement rate that the final rule imposes is not just and reasonable and has no basis in law. The final rule has removed any serious state role in agreeing to the final rule's planning and cost allocation processes, and the final rule fails to protect consumers as FERC is required to do under the FPA. Further, the cost causation principle cannot, and should not, extend as far as the today's final rule suggests, and should not require that the ratepayers of a non-consenting state pay costs of other states' public policies where there is mismatch between planning criteria and benefits.

1. The Final Rule Reverses the States' Roles in Transmission Planning and Cost Allocation Promised by the NOPR

68. The main reason I supported the NOPR was that it ''*formally* put the states—for the first time—at the center of regional transmission planning and cost allocation decision-making for policy-driven projects in *all* regional transmission entities, if the states choose.'' [165] Specifically, I explained:

[F]or these [Long-Term Regional Transmission Facilities] the NOPR propose[d] to require the regional planning entities to consult with *and seek the agreement of* the relevant states to *both* the selection criteria for these projects *and* to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects—such as, for example, the ''highway-byway'' formula approved by the SPP Regional State Committee—or states can agree to a process for a project-by-project agreement on cost allocation among one or several states—such as, for example, the State Agreement Approach in PJM—or states may choose some combination of both. States in a multi-state RTO or ISO can even agree to defer the decision on cost allocation to the governing board of the RTO/ISO. The result is, while we are proposing to require regional planning entities to study and evaluate a broad, forward-looking array of information—including information addressing states' individual energy policies and goals—any projects identified through this new process will not be built, or more importantly, paid for by consumers, until the states representing such consumers have agreed that such projects are indeed needed and wanted by those same consumers.[166]

I wrote about the advantages of elevating the role of the states:

[E]levating the role in planning and cost allocation of state regulators—who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component—will make it more likely, not less, that necessary transmission can get built while ensuring that rates resulting from these types of policy-driven projects will not be unjust and unreasonable, which they clearly have the potential to be.[167]

The day the Commission issued the NOPR, some of my colleagues expressed similar sentiments.[168]

69. Unfortunately—perhaps emanating from the final rule's erroneous legal conclusion that the Commission has exclusive jurisdiction over regional transmission planning and cost allocation [169]—the final rule completely eviscerates the states' role contemplated in the NOPR in both the transmission planning and cost allocation processes. Other than a few cosmetic gestures, the final role essentially treats the state regulators like other stakeholders in the RTO/ISO. But states are not mere ''stakeholders:''

State regulators have the duty to act in the *public interest* and states alone are sovereign authorities with inherent police powers to regulate utilities through their designated state officers. The FPA itself explicitly recognizes state authority. So it is perfectly fitting for state regulators to have the important roles proposed in this NOPR,

[157] *Id.*

[158] *See South Carolina,* 762 F.3d at 67 (quoting *Associated Gas Distribs.* v. *FERC,* 824 F.2d 981, 1019 (D.C. Cir. 1987)) (alteration in the original).

[159] *See generally* Final Rule, 187 FERC ¶ 61,068 at PP 71–77.

[160] *Id.* P 102; *see* OMS Initial Comments at 2 (stating that ''it is critically important to note at the outset that MISO's regional planning process already reflects many of the elements and features contained in the [NOPR], and it should be looked to as a model for other regions to emulate.''); MISO Initial Comments at 1–2.

[161] CAISO Initial Comments at 3 (''The CAISO already engages in long-term planning, and its existing transmission planning process is consistent with the direction of the NOPR.''); CAISO Reply Comments at 1–2 (stating that ''the Commission should not unduly disrupt or undo existing planning processes and approaches that are functioning well and enabling transmission providers to plan for system needs efficiently and cost-effectively.'').

[162] New York Commission and NYSERDA Initial Comments at 5.

[163] *See, e.g.,* Southern Companies Initial Comments at 13–15 (stating that its ''IRP/RFP-driven transmission planning is successfully expanding their electric grid to address the changing resource mix and load''); Undersigned States Reply Comments at 6–7.

[164] NRECA Initial Comments at 14–16.

[165] NOPR Concurrence at P 5 (emphases in original) (footnote omitted).

[166] *Id.* P 11 (emphases in original) (footnotes omitted).

[167] *Id.* P 14 (emphasis in original).

[168] *See supra* n.48; NOPR, 179 FERC ¶ 61,028 (Phillips, Comm'r, concurring at P 4) (''I support the proposal to require transmission providers to consult with and incorporate states' views in project selection and cost allocation. I invite comment on the value of such state involvement for increasing the likelihood that those facilities are sited and ultimately developed with fewer costly delays.''), *https://www.ferc.gov/news-events/news/item-e-1-commissioner-phillips-concurrence-building-future-through-electric.*

[169] *See supra* Section III.C.

without preempting the regional planning entities from seeking additional input through their existing stakeholder processes.[170]

The evisceration of the states' role in transmission planning and cost allocation and the relegation of state regulators to mere ''stakeholder'' status is alone reason enough for me to dissent.

a. The Final Rule Undercuts the States' Role in the Transmission Planning Process

70. A major example of the final rule's undercutting of the states' role in the transmission planning process is with respect to the selection criteria. As a reminder, the selection criteria are a key component of the planning process because once a project is selected, money starts to flow from the ratepayers to transmission developers. Recognizing the states' important role in the planning process, the NOPR required that the states *approve* the selection criteria that transmission providers use in the planning process:

Given the important role states play and the wide variety of potential approaches to selection criteria, we propose, as part of this requirement, that public utility transmission providers must consult with and seek support from the relevant state entities, as defined below, within their transmission planning region's footprint to develop the selection criteria.[171]

To implement this requirement, the NOPR proposed ''to require that public utility transmission providers demonstrate on compliance that they developed their proposed selection criteria in consultation with the relevant state entities in their transmission planning region's footprint.'' [172] And it was clear at that time exactly what that meant—*agreement, nothing less.*[173] However, the final rule outright undermines these requirements—and the states' role as a whole—by ''clarifying'' that state approval of the evaluation process and selection criteria is *not actually required:*

We clarify that we require transmission providers to *seek support* from Relevant State Entities, but *do not require transmission providers to obtain their support,* before proposing an evaluation process and selection criteria on compliance.[174]

Starkly demonstrating how milquetoast the requirement for transmission providers to ''consult with and seek support from'' the states has now become under the final rule, the final rule even fails to require that transmission providers indicate in their compliance filings whether the states agree with their selection criteria proposal.[175] So, from the NOPR requiring state agreement, the final rule does not even require the states' views to merit mere mention. Adding insult to injury, the final rule specifies that ''transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities.'' [176]

71. The final rule acknowledges that ''Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation process and selection criteria.'' [177] But the final rule emphasizes that transmission providers are ultimately the only ones responsible for transmission planning and complying with the obligations of the final rule, and it notes that achieving consensus may simply not be possible in every instance.[178] Neither explanation provides a sufficient rationale to justify undercutting the requirement for state approval when states alone have the inherent police power to regulate the utilities within their states. One cannot help but see this as part of the larger pretextual shell game the final rule seeks to accomplish. Sadly, this is one of many examples where the final rule provides for a little extra process involving the states to demonstrate ostensibly that the Commission is committed to the principle of cooperative federalism, but in substance, states are relegated back to mere stakeholders, whose input can simply be disregarded if inconvenient.[179]

72. Unfortunately, not only the states' role with respect to the selection criteria has been gutted. As I must continue emphasize,[180] by mandating categories of factors and minimum benefits, the final rule seeks to shape specific policies and outcomes, regardless of the consent of the states.[181] The goal of this pretextual final rule is to plan preferential policy and corporate-driven projects regardless of states' support. One must also ask whether the extent to which this final rule requires prescriptive planning processes also limits the states' role to participate meaningfully when most are resource-strapped.

73. States did not join RTOs [182] to pay for these preferential policy and corporate-driven projects. Rather, as I wrote in my concurrence to the NOPR, ''States joined to provide their retail consumers with the promised benefits of lower transmission costs and strengthened reliability through regional planning of core Reliability projects.'' [183] I speak from personal experience. When I was a Commissioner at the Virginia State Corporation Commission, my colleagues and I considered applications to permit Virginia's major utilities to join PJM. The Virginia Commission's rules required us to examine ''among other things, an [RTO's] reliability practices, pricing and access policies, and independent governance.'' [184] When we voted to approve the applications, PJM's planning for public policy projects that would be cost allocated regionally was not even on our radar.

b. The Final Rule Guts the States' Role in Cost Allocation as Proposed in the NOPR

74. Given the pretextual nature of this rule, it should not be surprising that it eviscerates the states' role in deciding cost allocation matters. NARUC strongly supported the NOPR's proposal to involve states in the cost allocation for Long-Term Regional Transmission Facilities and conversely disagreed with a requirement that transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from the states.[185] NARUC explained:

[S]ince the projects under consideration in the Long-Term Regional Transmission Planning process are largely driven by state public policies, state regulators should have a key role in evaluating the benefits and allocating the costs. State regulators are attuned to the concerns of the local communities where the transmission will be sited and the retail ratepayers who must, in many instances, foot a large fraction of the cost.[186]

Of course, to effectuate the pretextual agenda, the final rule simply ignores NARUC's entreaties and instead cuts the

[170] NOPR Concurrence at P 13 (emphasis in original).

[171] NOPR, 179 FERC ¶ 61,028 at P 244; *see also* NOPR Concurrence at P 11 (''State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements.'').

[172] NOPR, 179 FERC ¶ 61,028 at P 246.

[173] *See* NOPR Concurrence at P 11; *see also supra* n.48.

[174] Final Rule, 187 FERC ¶ 61,068 at P 996 (emphases added).

[175] *Id.* P 999.

[176] *Id.* P 962 (emphasis added).

[177] *Id.* P 996.

[178] *Id.*

[179] *See supra* P 69.

[180] *See supra* Section I. Another example, of course, is micromanaging how local ''stakeholder'' meetings must be conducted, which, as noted, runs a strong risk of conflicting with state IRP proceedings and state authority. *See* Final Rule, 187 FERC ¶ 61,068 at PP 1625–1646. As above, I question whether prescriptive requirements to this degree can truly pass muster under court precedent.

[181] And transmission providers themselves cannot even voluntarily account for states' input in the planning. Today's final rule requires that transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Final Rule, 187 FERC ¶ 61,068 at P 962.

[182] I am aware that states *qua* states do not join RTOs/ISOs. Rather, they use their regulatory power to allow or require their regulated transmission-owning utilities to join.

[183] NOPR Concurrence at P 13.

[184] *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter concerning the application of Virginia Electric and Power Company d/b/a Dominion Virginia Power for approval of a plan to transfer functional and operational control of certain transmission facilities to a regional transmission entity,* Case No. PUE–2000–00551 (Nov. 10, 2004). The order included a stipulation in which Dominion agreed that joining PJM would not alter its legal obligation to seek a CPCN from the Virginia Commission to construct generation or transmission assets. *Id.,* Partial Stip. ¶ 6.

[185] NARUC Initial Comments at 45.

[186] *Id.* at 46 (citations omitted).

states out of any meaningful role in cost allocation.

75. First, the final rule essentially terminates the State Agreement Process by making the *ex ante* cost allocation method the default approach. While the NOPR proposed to require transmission providers to revise their OATTs to include *either* (1) an *ex ante* cost allocation method (*i.e.,* a Long-Term Regional Transmission Cost Allocation Method) to allocate the costs of Long-Term Regional Transmission Facilities, (2) a State Agreement Process, or (3) a combination thereof,[187] the final rule substantially modifies the NOPR proposal to require the use of one or more *ex ante* cost allocation methods.[188] Although the final rule permits transmission providers to include a State Agreement Process in their OATTs if the states agree, the final rule specifies that the State Agreement Process ''cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities,'' [189] and the final rule modifies the NOPR proposal to require an *ex ante* cost allocation method to apply as a backstop.[190] The *ex ante* cost allocation method backstop would apply if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and others *or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential.*[191]

76. Second, under the final rule, state consent on cost allocation is not required. The final rule explicitly declines to adopt the NOPR proposal to require transmission providers to seek the agreement of the states regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[192] Instead, the final rule merely requires transmission providers to establish a six-month Engagement Period ''to provide a forum'' for the states to negotiate an *ex ante* cost allocation method(s) and/or a State Agreement Process.[193] Under the final rule, if the negotiations fail, transmission providers must still file an *ex ante* cost allocation method(s).[194] Worse still, the final rule specifies that, even if the states *do* reach an agreement on an *ex ante* cost allocation method(s) and/or a State Agreement Process, the transmission providers *may ignore* it and file their own *ex ante* cost allocation method(s) instead.[195]

Similarly, the final rule declines to require that, if the transmission providers disagree with a proposed cost allocation method agreed on by the states, transmission providers must file both cost allocation methods: the transmission providers' preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities. So to the states, the final rule says, ''Heads I win, tails you lose.''

77. Further, under the final rule, at the end of the Engagement Period, the states' role—however small—in shaping an *ex ante* cost allocation formula is effectively over. NARUC argued that the Commission should provide some mechanism for future review of cost allocation methodologies for Long-Term Regional Transmission Facilities given that state public policies may evolve:

> As the name suggests, these transmission facilities are expected to be planned over a longer period of time than projects built for reliability or economic reasons. States that do not currently have public policies requiring extensive transmission investments may forego an opportunity to participate in discussions regarding cost allocation, but their public policies may evolve over time. For the reforms proposed in this NOPR to be successful, the positions of relevant state entities should not be frozen in time.[196]

But the final rule denies this request.[197] Further, the final rule specifies that transmission providers may file subsequent changes to their cost allocation method(s) *without establishing future Engagement Periods* beyond the initial one.[198]

78. As noted above, the upshot of these changes, taken together, is that the states are simply cut out of any significant role in the cost allocation of the of Long-Term Regional Transmission Facilities. The final rule completely eviscerates the State Agreement Process and renders it non-viable. The final rule eliminates the core element of that approach—that states enter such cost allocation arrangements *voluntarily.* Now—with an *ex ante* cost allocation method that must serve as a backstop in the event that the states' negotiations fail, looming over the states' heads like the sword of Damocles—the final rule gives states ''an offer they can't refuse,'' telling the states that must they agree to a cost allocation or the transmission providers will impose one on them anyway. In such a circumstance, fruitful negotiation between the states is virtually impossible, as states simply cannot say ''no.'' At the risk of stating the obvious, this forced cost allocation on the states is, of course, contrary to comments of NARUC and many of the individual states.[199]

79. Just as concerning, as I discuss in Sections I and IV.B.2 of this dissent, the final rule will enable the ratepayers of non-consenting states to be assessed the cost of public policy projects of other states, which is anti-democratic and violates the basic principle of fairness. As NARUC points out, NARUC and individual state commissions supported the State Agreement Process to address this concern:

> NARUC is particularly supportive of the State Agreement Process, which is similar to the PJM State Agreement Approach that has been approved by FERC and that NARUC and state commissions advocated to be included in the final rule. A state agreement approach allows states to further their public policy goals without burdening the ratepayers of states that have different priorities.[200]

The final rule's gutting of the very State Agreement Process that NARUC supports as part of the final rule's choice to ignore the consent of the states on cost allocation removes this key protection for the states and their ratepayers.

80. Further, given the final rule's determinations undercutting the states' role,

[187] NOPR, 179 FERC ¶ 61,028 at P 302.

[188] Final Rule, 187 FERC ¶ 61,068 at P 1291.

[189] *Id.* PP 1292, 1361, 1404.

[190] *Id.* P 1292.

[191] *Id.* P 1293.

[192] *Id.* P 1354.

[193] *Id.* P 1357.

[194] *Id.* P 1367.

[195] *E.g., id.* P 1359 (''[T]he ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.''); *id.* P 1429 (''[A]fter the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings. Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method *and not file a State Agreement Process or other ex ante cost allocation method to which Relevant State Entities agreed.* In addition, *we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree,* even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.'') (emphases added; footnote omitted); *see also id.* P 1356 n.2895 (citing *Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1, 9 (D.C. Cir. 2002) (*Atlantic City*)).

[196] NARUC Initial Comments at 49.

[197] Final Rule, 187 FERC ¶ 61,068 at P 1368.

[198] *Id.*

[199] *See* NARUC Initial Comments at 45 (''NARUC strongly supports the Commission's proposal to involve states in cost allocation for Long-Term Regional Transmission Facilities and conversely explicitly rejects a requirement that public utility transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from relevant state entities.'') (footnotes omitted); *see, e.g.,* Alabama Commission Initial Comments at 9 (''In other words, states may not force their preferences on their neighbors, or compel them to subsidize their achievement. Thus, it goes without saying that Alabama ratepayers should not be required to pay for transmission projects that are designed to promote or facilitate the public goals of other states, localities, or entities.''); West Virginia Commission Reply Comments at 2–3 (''The [West Virginia Commission] opposes any changes in transmission cost allocation that would require West Virginia customers, or customers of any State, to involuntarily pay for new transmission facilities that are needed to support the public policy generation choices of other States.''); North Carolina Commission and Staff Initial Comments at 15–16 (''The [North Carolina Commission and Staff] strongly support the NOPR proposals regarding cost allocation for regional transmission facilities developed through the Long-Term Regional Transmission Planning process, as that term is defined in the NOPR, specifically the requirement for transmission providers to seek state agreement on cost allocation methodologies and the requirement to create an opportunity for states to negotiate a cost allocation method after a transmission facility has been selected through the Long-Term Regional Transmission Planning process.''); Utah Commission Initial Comments at 9 (''[I]mposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of FERC's authority under Section 206.'').

[200] NARUC Initial Comments at 51 (footnote omitted).

I highly doubt that PJM's State Agreement Approach or other existing mechanisms involving the states in other RTOs will remain viable with respect to the cost allocation of Long-Term Regional Transmission Facilities.[201] In addition to PJM's State Agreement Approach, NARUC notes that the country's other multi-state RTOs have mechanisms in place for the states to participate in regional transmission cost allocation:

In many regions, state regulators are at the forefront of successful efforts to coordinate regional transmission, including what many understand to be the most challenging issue, cost allocation. For instance, in SPP, the Regional State Committee has the primary authority for setting the basis of any regional cost allocation. In both MISO and ISO-New England, state committees have the ability to propose alternative cost allocation methodologies under some circumstances.[202]

81. Specifically, SPP has a Regional State Committee (RSC) process by which the RSC has agreed to a ''highway-byway'' *ex ante* cost allocation and SPP will file it,[203] and MISO's Tariff provides that MISO will file under FPA section 205 OMS's alternative cost allocation to MISO's proposal.[204] Given that the final rule's determination that transmission providers may ignore any agreement or alternative proposed by the states,[205] such mechanisms could be called into question—unless the RTOs *voluntarily* agree to preserve them in their OATTs.[206] If these mechanisms are weakened, or even eliminated, the only alternatives left for the states to shape the RTOs' cost allocation would be to file comments to the RTOs' cost allocation filings or to file a section 206 complaint—no different than any RTO stakeholder.

82. The final rule acknowledges that ''experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states.'' [207] However, the final rule's determinations on cost allocation undercut this critical role. It appears obvious that the final rule does not in fact view the states as partners in a cooperative federal system, but rather as potential obstacles to its pretextual political, corporate, and ideological agendas.

83. The final rule sets forth two central arguments for its dramatic reduction of the states' role. First, the final rule suggests that, per *Atlantic City,*[208] the Commission cannot deprive transmission providers of their FPA section 205 filing rights to propose tariff changes to rates.[209] And second, the final rule claims that if transmission providers were permitted to rely solely on a State Agreement Process to determine the cost allocation and that process were to fail, ''there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs,'' and ''[a]s a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized.'' [210] Both arguments are without merit.

i. The Final Rule Takes Far Too Broad a View of Atlantic City

84. *Atlantic City* is often discussed as a bar to FERC's ability to take meaningful action on many issues, including transmission cost allocation.[211] But *Atlantic City* does not stand for an outright prohibition on Commission action, especially under FPA section 206, under which this pretextual rule purports to act. All *Atlantic City* stands for is that ''transmission-owning utilities have 'filing rights' under section 205 that FERC may not *revoke.*'' [212] *Atlantic City* does not prevent FERC from granting additional filing rights to other entities, including *state regulators,* if it determines that existing practices, including RTO independence, are unjust and unreasonable and unduly discriminatory or preferential.[213]

85. In a similar vein, *Atlantic City* does not require FERC to force non-consenting states to pay for other states' policy projects, as today's final rule implies.[214] The final rule's reliance on *Atlantic City* in this regard is simply a way for FERC to sidestep action that will truly ensure that needed transmission gets built with the cooperation, support, and assent of the states. Instead, what we have in today's final rule is a patent instance of regulatory capture with the singular goal to build out preferential policy and corporate-driven projects, steamrolling the states and consumers alike. And to be clear, nothing meaningfully prevents the NOPR compromise that would have maintained or elevated the states' role in transmission planning and cost allocation even further. In fact, even accounting for *Atlantic City,* the NOPR compromise was a worthwhile solution to getting the transmission that is *actually* needed to serve organic load built.

ii. The Commission Fails Consumers by Unreasonably and Unfairly Socializing Policy- and Corporate-Driven Costs Across Captive Customers

86. The final rule's claim that the Long-Term Regional Transmission Facilities selected are ''the more efficient or cost-effective solutions to Long-Term Transmission Needs'' [215] is disingenuous. As I discuss above in Section I, in a sleight of hand move, the final rule lumps together in one bucket for planning and for cost allocation purposes projects that address policy-driven and corporate-driven needs with those that address reliability and economic needs. The final rule's goal is to socialize the costs associated with preferential policy and corporate-driven projects across the multi-state regions, even when the states have never consented for their consumers to pay for such projects. But

[201] PJM's State Agreement Approach exemplified the proper way to involve states in decisions regarding cost allocation for public policy projects. The PJM State Agreement Approach was not directed by Order No. 1000, but rather by PJM's own voluntary act of reaching out to the states in PJM States and asking PJM States to propose a cost allocation for public policy projects. PJM accepted PJM States' proposal—which became the PJM State Agreement Approach—and submitted it to FERC in its compliance filing. It was accepted by FERC, but as today's final rule shows, only grudgingly and only until the chance came to extinguish it.

[202] NARUC Initial Comments at 46 (citing MISO Transmission Owners Agreement, Appendix K, Article II, Section II.E.3.b (providing regional state committee with the opportunity to develop and request MISO file an alternative cost-allocation methodology under certain circumstances); ISO New England, Agreements and Contracts, Transmission Operating Agreement, Section 3.04 (h)(vi)(A–C) (providing regional state committee with opportunity to provide alternative cost allocation proposal in connection with certain transmission cost allocation provisions in ISO–NE's tariff)).

[203] *See* SPP, Governing Documents Tariff, § 7.2 (Bylaws 7.2 Regional State Committee) (2.0.0); *see also Sw. Power Pool, Inc.,* 106 FERC ¶ 61,110, at P 219, *order on reh'g,* 109 FERC ¶ 61,010, at PP 93–94 (2004); *Entergy Arkansas, Inc.,* 133 FERC ¶ 61,211, at P 15 (2010).

[204] *E.g., Midwest Indep. Transmission Sys. Operator, Inc.,* 143 FERC ¶ 61,165, at PP 30–31 (2013) (citations omitted).

[205] *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 1359, 1429; *see also id.* P 1356 n.2895 (citation omitted).

[206] *See, e.g., id.* P 1412 (''[N]or do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs); *id.* n.3013 (''[T]ransmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.'').

[207] *Id.* P 124.

[208] 295 F.3d 1.

[209] *E.g.,* Final Rule, 187 FERC ¶ 61,068 at P 1363 & n.2909; *id.* P 1356 n.2895.

[210] *Id.* P 1293.

[211] 295 F.3d at 9–11.

[212] *See also* Peskoe Article at 572 (emphasis added), a thorough and helpful distillation of the intricacies of FPA sections 205 and 206 as to RTO governance. *See also id.* at 567.

[213] *See id.* at 614–615 (''To bolster RTO independence, FERC could expand filing rights over regionally significant issues that are currently controlled by the [investor-owned utilities (IOUs)], such as *cost allocation for regional transmission expansion.* . . . State regulators are also potential beneficiaries. State utility commissions comprehensively regulate IOUs' local service and are familiar with IOUs' local operations and planning. *State filing rights might serve a consumer protection function, as state regulators are ultimately responsible for ensuring that retail rates, which include costs of RTO-planned transmission projects and RTO-administered markets, appropriately account for consumers' interests.* As noted, MISO and SPP agreements already provide state regulators with limited filing rights over transmission cost allocation or resource adequacy, two areas where states have overlapping oversight . . . . *Providing states with meaningful roles in RTO processes might mitigate future conflicts between states' priorities and RTO rules and planning processes.*'') (emphases added) (footnotes omitted). Let me add my strong endorsement to granting states section 205 filing rights with respect to cost allocation. The final rule, of course, goes in the opposite direction.

[214] *See e.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 1356 n.2895, 1429–1431.

[215] *Id.* P 1293.

requiring the ratepayers of a non-consenting state to pay for the public policy projects of another state cannot reasonably be deemed ''efficient'' or ''cost-effective.''

2. The Final Rule Requires Consumers in Non-Consenting States To Pay the Costs of Other States' Public Policy Projects

a. The Costs of Public Policy-Driven Projects Must Not Be Imposed on Non-Consenting Consumers Without State Regulatory Oversight

87. In my NOPR Concurrence, I noted that ''no individual state's consumers can be forced to bear the costs of another state's policy-driven project or element of a project against its consent.'' [216] I have adamantly maintained this position in subsequent Statements:

The costs related to a public policy project . . . should be borne by the sponsoring state and not shifted to consumers in other states without the consent of responsible officials in those states, who can then be held accountable by the voters of that state for their decisions (as can officials in the sponsoring state). That is how democracy is supposed to work.[217]

I have explained that if the people and businesses of the sponsoring state do not like the impacts of their state's public policies, ''their recourse is to the ballot box,'' [218] but that in contrast, ''[c]onsumers in other states do not have such recourse, which is why these costs must be confined to [the sponsoring state].'' [219]

88. I have written before that ''imposing the costs of a project driven by one state's public policies onto another state that has not consented to such cost allocation would, in my view, presumably result in unjust and unreasonable rates.'' [220] Such imposition would be contrary to basic fairness, a core principle of American democracy:

For if democracy means anything at all, it means that the people have an inherent right to choose the legislators to whom the people grant the power to decide the major questions of public policy that impact how the people live their daily lives. . . . That is the basic constitutional framework of the United States and it is the same for any liberal democracy worth the name.[221]

The final rule subverts this principle.[222]

b. Certain States Are Not ''Cost Causers'' for Cost Allocation Purposes

89. Today's final rule provides very little in the way of support for its cost allocation requirements, despite the extensive changes to planning requirements.[223] This final rule simply assumes that it is on sound footing as to cost causation. But that is not the case. While *some* precedent cited by today's final rule sheds some indirect light on the cost allocation issues implicated here,[224] at its core, today's final rule involves a new application of the cost causation principle to justify the final rule's pretextual agenda. It intends to force consumers in one state to pay for the costs of public policies enacted by politicians in another state and corporate purchasing preferences. But those costs and the resulting rates cannot be considered just and reasonable in any universe.

90. We are at the point where we must argue that not *all* consumers in certain states are ''cost causers'' simply because they have joined a multi-state RTO or fall within a transmission planning region. These consumers are not the ''but for'' cause of many of the Long-Term Transmission Needs required by the consideration of the specified categories of factors in today's policy agenda-driven rule. Nor are such consumers the intended beneficiaries of public policies in states enacted by politicians for whom they never voted. Indeed, absent rational limits on the ''free rider'' concept that the cost causation principle is meant to address, anyone can be deemed a beneficiary of any transmission project anywhere.

91. That policy-caused costs cannot be attributed to consumers who did *not* cause the policy is consistent with case law. As articulated mostly clearly by the D.C. Circuit, the cost causation principle means that ''all approved rates [must] reflect to some degree the costs *actually caused* by the customer who must pay them.'' [225] This has been oft repeated by many courts over the years, including most notably the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) in *Illinois Commerce Commission* v. *FERC*.[226] The Seventh Circuit expanded on this further to state that, ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.'' [227]

92. Tied to the cost causation principle is the concept of ''free ridership.'' As explained by the Commission in Order No. 1000–A, a free rider is an ''entity is not required to pay for a benefit it receives'' [228] and is the form of ''subsidization'' against which the cost causation principle is supposed to protect.[229]

93. As explained in Order No. 1000–A, the Commission treats each transmission customer not as using a single transmission path but rather as usual the entire transmission system and views such service as service over the entire grid.[230] The Commission explained:

Given the nature of transmission operations, it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. This is the essence of the ''free rider'' problem the Commission is seeking to address through its cost allocation reforms. Any individual beneficiary of a new transmission facility has an incentive to defer investment in the anticipation that other beneficiaries in the region will value the project enough to fund its development. This can lead to situations in which no developer moves forward, adversely affecting development of transmission facilities and, as a result, rates for jurisdictional services.[231]

Therefore, the Commission explained that the cost allocation provisions of Order No. 1000 (the failures of which allegedly justify the changes contemplated by today's final rule), which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, were consistent with the statement in *ICC*

[216] NOPR Concurrence at P 12 (citing NOPR, 179 FERC ¶ 61,028 at PP 302, 312).

[217] *N.Y. Power Auth.*, 185 FERC ¶ 61,102 (2023) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-nypas-abandoned-plant-incentive-el23; N.Y. Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,004 (2022) (Christie, Comm'r, concurring at P 2).

[218] *E.g., N.Y. Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,101 (2022) (Christie, Comm'r, concurring at P 5), *https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-independent*.

[219] *N.Y. Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,184 (2024) (Christie, Comm'r, concurring at P 2).

[220] *NSTAR Elec Co.*, 179 FERC ¶ 61,200 (2022) (Christie, Comm'r, concurring at P 10), *https://www.ferc.gov/media/e-13-er22-1247-000; see also N.Y. Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,101 (Christie, Comm'r, concurring at P 6) (''A similar analysis could well lead to a different outcome in a *multi-state* RTO, if the record showed that the RTO was implementing one state's public policies as to preferred resources, and that implementation resulted in impacts being shifted to consumers in one or more other states in the multi-state RTO. *Such impacts and cost-shifting in multi-state RTOs, if proven by the record, could well be unjust, unreasonable and unduly discriminatory or preferential under the FPA.*'') (emphasis in the original and added); *N.Y. Pub. Serv. Comm'n* v. *N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110 (2021) (Christie, Comm'r, concurring at P 3) (''I also note that the NYISO is a single-state ISO and I have been able to locate no evidence in the record that the New York policies at issue in today's order are causing cost-shifting onto consumers in other states. *If consumers in other states were disadvantaged, I may well view this matter differently.*'') (emphasis added), *https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-state-public; cf.* Commissioner Mark C. Christie, Fair RATES Act Statement on PJM Minimum Offer Price Rule (MOPR) Revisions, Docket No. ER21–2582–000 at P 6 (Oct. 19, 2021) (''I would have proposed that PJM formulate a replacement for the current MOPR based on three broad principles: (1) a state may designate specific or categorical resources as 'public policy resources' and such designated resources will be funded through a mechanism *chosen by the state* outside of the capacity market . . . and (3) *non-sponsoring state consumers would not be forced to pay for another state's designated public-policy resources.*'') (footnotes omitted) (emphasis in the original and added), *https://www.ferc.gov/news-events/news/commissioner-christies-fair-rates-act-statement-pjm-mopr*.

[221] Certificate Dissent at P 63.

[222] *Infra* Section IV.B.2.b.

[223] *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 266, 269, 279, 1304, 1478–1479.

[224] As an aside, I question whether some of the precedent cited by today's final rule in support of the cost causation issue is truly apposite when you look at the facts in those cases.

[225] *KN Energy, Inc.* v. *FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (emphasis added).

[226] 576 F.3d 470, 476 (7th Cir. 2009) (*ICC*).

[227] *Id.*

[228] Order No. 1000–A, 139 FERC ¶ 61,132 at P 573.

[229] *Id.* P 578.

[230] *Id.* P 560 (citations omitted).

[231] *Id.* P 562 (internal citation omitted).

that ''[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.'' [232] Indeed, all of the precedent relied upon in today's final rule signals that free ridership is a concern solely based on the assumptions underlying the transmission planning. And herein lies the deception—the more you plan and account for, the bigger and more regionalized you can argue the cost allocation framework should be. Which makes sense when the goal of today's final rule is to enact a sweeping policy agenda and thus socialize the costs across consumers in a multi-state region.

94. The main support for the cost causation principle is *ICC*,[233] for the exact quote noted above. However, often omitted from the discussion of *ICC* is the context and outcome of the case. In that case, the Seventh Circuit remanded the Commission's approval of cost allocation concerning ''Project Mountaineer'' [234] (yes, the same one that prompted PATH) for lack of substantial evidence regarding the FERC-approved cost allocation. In addition to the quote above, the Seventh Circuit also expressed the following: ''FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, *or benefits that are trivial in relation to the costs sought to be shifted to its members.*'' [235] And it merits repeating that ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, *as without the expectation of its contributions the facilities might not have been built, or might have been delayed.*'' [236] So, given the extent to which the Long-Term Transmission Needs contemplated by today's final rule factor in state public policies and special interests' goals, you would expect the only beneficiaries for cost allocation purposes to be states with those public policies or other special interest drivers of the transmission.

95. Unfortunately, you would be wrong. Due to the final rule requiring planning for any and every transmission need and mandating minimum reliability and economic benefits as part of the planning process, projects developed primarily for preferential policy and corporate purposes will necessarily have the broadest array of so-called beneficiaries possible, all identified prior to selection.[237] These so-called beneficiaries will then be forced to pay for these projects, simply because they may receive some trivial benefits due to their participation in a regional transmission system. These so-called beneficiaries will be treated as ''cost causers'' even though their contributions *do not* ensure the projects get built nor ensure that the projects are not delayed. Today's final rule, of course, even emphasizes that, as to why today's final rule does not require the consideration of public policy benefits, it ''does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities.'' [238] But this is because today's final rule already determined the minimum reliability and economic benefits that all projects contemplated by the final rule must have. Adding in public policy benefits would shift the resulting cost allocation to show the *actual* beneficiaries—the states with preferred policies and corporate and special interests. So, through a mismatch in planning criteria and benefits, today's final rule ensures socializing the costs of preferential policy and corporate-driven projects onto states and consumers that will ultimately receive trivial benefits, in violation of *ICC*. If you find all this confusing, the final rule is intended to be. That's why it's a shell game.

96. At its core, *ICC* is simply a baseline regarding the cost causation principle's application. That is, the Commission cannot require cost allocation to a particular group of utilities, *i.e.*, consumers, where there is *no* evidence of benefits. Its findings should not be distorted, as today's final rule suggests through Orwellian newspeak, to support a mismatch of planning criteria to benefits to strongarm a cost allocation regime to get preferential policy and corporate-driven projects built.

97. Also referenced by today's final rule for cost causation is *South Carolina*.[239] In the context of cost causation, the D.C. Circuit concluded that ''the Commission's adoption of a beneficiary-based cost allocation method is a logical extension of the cost causation principle.'' [240] The court added that it had ''endorsed the approach of 'assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.' '' [241]

98. The final rule does not simply require a beneficiary-based cost allocation, like Order No. 1000. Instead, as I *must continue to emphasize*, it requires mandating reliability and economic benefits during the planning process to shoehorn the broadest group of beneficiaries possible for projects that do not remotely relate to reliability and economic needs.[242] This is not a ''light touch'' that ''does not dictate how costs are to be allocated.'' [243] Today's final rule may attempt to sequester the beneficiaries of these reliability and congestion benefits from the cost allocation ''benefits'' by not clearly linking the two,[244] but in what reality will a transmission provider seeking to comply with today's final rule identify *different* beneficiaries from those identified in the planning process? The result of this shell game is to ensure preferential policy and corporate-driven projects are selected with the widest group of beneficiaries possible, so as to socialize the costs across the widest group of consumers.[245]

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[232] *Id.* P 565 (citing *ICC*, 576 F.3d 470 at 476) (alterations in the original). In Order No. 1000, the Commission also found that ''[b]eneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state's transmission needs driven by Public Policy Requirements.'' Order No. 1000, 136 FERC ¶ 61,051 at P 545. ''If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits because Public Policy Requirements played a role in the decision to construct the transmission facility.'' *Id.* While Order No. 1000 may have successfully established this to be the case, per *South Carolina*, today's final rule is not similarly situated to Order No. 1000 with its required minimum benefits, selection criteria, and utter disregard of the states' role in planning and cost allocation. *See supra* Section III.A. Today's final rule instead creates beneficiaries for projects that are primarily public policy-driven, based on the categories of factors required to be considered in today's final rule's planning requirements.

[233] 576 F.3d 470.

[234] *See* PATH Concurrence at P 4 (providing a history on Project Mountaineer). Relying on a case that remanded the Commission's *approval* of cost allocation associated with a regional transmission project that never came to fruition is nothing short of ironic.

[235] *ICC*, 576 F.3d at 476 (emphasis added).

[236] *Id.* (emphasis added). *See* NARUC Initial Comments at 33–34 (''Long-Term Regional Transmission Planning must recognize that benefits inherently become more speculative as the planning horizon increases. Additionally, planning based on public policy objectives must be transparent about identifying projects that would not be selected but for those public policy objectives. *Benefits assigned to projects must recognize these principles.*'') (emphasis added).

[237] *See supra* Sections I, III.A; *see also* Final Rule, 187 FERC ¶ 61,068 at P 965.

[238] Final Rule, 187 FERC ¶ 61,068 at P 1515. This is why I have described this final rule as a shell game with respect to the issue of the benefit mismatch between planning and costs. By making the minimum required benefits reliability- and economic-focused, today's final rule ensures that the ''beneficiaries'' are those that are receiving some reliability and economic benefits. As we know from basic transmission planning, *any* transmission built is going to bring some reliability and economic benefits. So, any transmission planned through Long-Term Regional Transmission Planning for the identified Long-Term Transmission Needs will necessarily bring some reliability and economic benefits. And by *not* requiring a matching of benefits to the Long-Term Transmission Needs that are planned for, in this case public policy benefits, the resulting benefits of any one project will be skewed to indicate more ''beneficiaries'' than there would be if today's final rule accounted for public policy benefits separately. *See* NARUC Initial Comments at 33–34. If today's final rule accounted for public policy benefits or corporate goals separately, it would be clear who the *actual* drivers, and *actual* beneficiaries, of any one project are.

[239] 762 F.3d 41.

[240] *Id.* at 85.

[241] *Id.* (citations omitted).

[242] *See supra* Sections I, III.A.

[243] *See South Carolina*, 762 F.3d at 81; *see also supra* Section III.A.

[244] *See, e.g.*, Final Rule, 187 FERC ¶ 61,068 at P 1506 (''We do not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission.''). This provision illustrates the confusing and contradictory nature of the final rule and provides another example of the shell game.

[245] Today's final rule relies on several other cases in support of its oversimplification of the cost causation principle, such as *Old Dominion Electric Coop.* v. *FERC*, 898 F.3d 1254 (D.C. Cir. 2018), and *Long Island Power Authority* v. *FERC*, 27 F.4th 705 (D.C. Cir. 2022), among others, but the same is true of these cases—the Commission cannot strong-arm beneficiaries to get transmission built, and override the states to do so. Of course, this is primarily a problem in multi-state RTOs, but overriding the states with regulation based on a cooperative federalism statute is not in good faith and the result is terrible for consumers everywhere.

99. Today's final rule ultimately presents the wrong solution to the perceived problem of ''balkanized'' transmission planning.[246] Unfortunately, today's final rule devises the shell game to ensure that the biggest planning bucket means the biggest pool of potential beneficiaries. And to carry out the shell game, the final rule walks back cost allocation principle (6) because, without this change, today's final rule's preferred cost allocation framework does not work.[247]

100. NARUC and many individual states oppose the Commission's imposition of mandatory minimum benefits and would prefer a bottom-up rather than a top-down approach: ''The proposed list of benefits for consideration is a better way to accomplish the objectives of the NOPR than specification of benefits that must always be used in Long-Term Regional Transmission Planning.'' [248] Today's final rule blithely brushed these concerns aside.

101. To effectuate purported compliance with the cost causation principle, today's final rule ignores the principle of the *optimal solution* in transmission planning. For each identified reliability problem, there is an optimal solution that solves the reliability problem at the *least* cost to consumers. For an economic project, consumers should receive the *maximum* reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the *least* costs for the project. The final rule, by contrast, claims that a project that is driven by one state's public policies will still provide some reliability and congestion benefits to other states, so consumers in those states *must* be treated as beneficiaries.[249] But even assuming that consumers in those other states hypothetically receive some marginal reliability or congestion benefits, they are being overcharged for those benefits because the project includes the costs of another state's public policies or costs of projects to meet corporate goals, and the only benefits required to be considered by today's final rule are reliability and economic benefits. Consumers in the non-policy causing states are not receiving or paying for the optimal solution to an identified reliability problem or maximum congestion relief compared to the costs they are being forced to pay. As a consequence, the transmission *rates*—let's ignore the planning practices for a moment—they will be forced to pay are clearly unjust and unreasonable under the FPA.

3. The Final Rule Violates the Commission's Consumer Protection Duty Under the FPA

102. To add to the number of already unjust and unreasonable aspects in today's final rule, today's final rule is patently unfair to consumers. That much is apparent from its decision, through transmission planning and cost allocation processes: (1) to shift interconnection costs from generation developers to consumers through transmission planning, and (2) to shift the costs of, *inter alia,* a transmission project accommodating a corporate commitment from corporate consumers to other consumers. Today's final rule, equally harmful to consumers, walk backs the NOPR proposal to remove the CWIP Incentive, one of the major reasons I supported the NOPR in the first place. The final rule essentially uses the justification of efficiency and cost-effectiveness to create catastrophic outcomes for consumers. Such an anti-consumer outcome is simply unjust and unreasonable, and in this case, even unduly discriminatory and preferential.

a. The Final Rule Unlawfully Shifts Interconnection Costs From Developers to Consumers

103. In prior statements, I have frequently discussed the basic principle that generation developers should pay the costs to interconnect their generators to the grid:

[G]eneration developers in RTOs should pay the full ''but for'' costs of their interconnection, including network upgrades. Consumers (*i.e.,* load) should not pay one nickel. They are not the ones seeking to profit from the interconnection. New generation in RTOs is supposed to be driven by the market, not by integrated resource planning, as in non-RTOs. This is the compelling principle underlying participant funding of interconnection in RTOs.[250]

By requiring the coordination of regional transmission planning and generator interconnection processes and by requiring the incorporation of Factor Category Six: generator interconnection requests and withdrawals in the development of Long-Term Scenarios, the final rule causes consumers to subsidize generation developers and thus subverts this basic principle.

i. Coordination of Regional Transmission Planning and Generator Interconnection Processes Will Result in Unlawful Cost Shifts to Consumers

104. The final rule requires transmission providers in each transmission planning region to revise their existing Order No. 1000 regional transmission planning processes to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process.[251] As a result of this requirement, transmission providers may select in regional transmission plans for purposes of cost allocation transmission facilities designed to address certain interconnection needs and *will allocate the costs of such facilities to the load in that region.* This practice will force consumers to subsidize the interconnection costs of generator developers and in so doing turn them into the banks for the ventures, viable or otherwise, of generation developers—a classic example of the socialization of costs to enable private profit. Of course, this will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential.

105. The final rule's attempted justifications for this effort to shift interconnection costs to consumers are vacuous and fail to disguise the real agenda, which is to subsidize developers of preferred

[246] *See supra* Section IV.A.

[247] *See* Final Rule, 187 FERC ¶ 61,068 at P 1474.

[248] *See* NARUC Comments at 25; *see also* New York Commission and NYSERDA Initial Comments at 7 (''We urge the Commission to ensure that any final rule in this proceeding is sufficiently flexible to accommodate regional differences and avoid disrupting the processes already in place and otherwise underway in New York that are working well for the region.''); SPP Initial Comments at 18 (''How and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each public utility transmission provider and its stakeholders. This would allow for agility in process decisions to balance the value the analysis provides with the burden of the effort.''); ISO–NE Initial Comments at 5 (''Individual regions should be permitted to determine the benefits that will lead to transmission in the region.''); NYISO Initial Comments at 39 (''The final rule should confirm that each planning region is not required to use the specific benefits described in the NOPR . . . . While, in practice, the NYISO already uses most of the 12 illustrative benefits identified in the NOPR, the NYISO should be permitted to retain its flexibility to identify, with input from state entities and stakeholders, the benefits used in its processes and how such benefits are calculated.''); *id.* at 11 (''The final rule should not mandate strict requirements concerning how long-term transmission planning must be conducted.'').

[249] Final Rule, 187 FERC ¶ 61,068 at Section III.D.1.c.

[250] *See Midcontinent Indep. Sys. Operator, Inc.,* 184 FERC ¶ 61,190 (2023) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-order-concerning-funding; Midcontinent Indep. Sys. Operator, Inc.,* 184 FERC ¶ 61,156 (2023) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-gia-order-concerning-funding; Midcontinent Indep. Sys. Operator, Inc.,* 183 FERC ¶ 61,113 (2023) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-fsa-order-concerning-funding; Midcontinent Independent System Operator, Inc.,* 182 FERC ¶ 61,225 (2023) (Christie, Comm'r, concurring at P 2), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-and-fsa-orders-concerning-funding; see also Midcontinent Indep. Sys. Operator, Inc.,* 185 FERC ¶ 61,182 (2023), *order on reh'g,* 187 FERC ¶ 61,015 (2024), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-order-rejecting-miso-gia-concerning-funding*. This principle also applies to developers of merchant transmission lines who seek to interconnect. *Midcontinent Indep. Sys. Operator, Inc.,* 181 FERC ¶ 61,218 (2022) (Christie, Comm'r, concurring at P 1), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-funding-interconnection-costs-rtos*. If state regulators in a multi-state region agreed on a different cost allocation related to interconnection costs that they believed protected consumers from unfair treatment, then such alternative would merit consideration.

[251] Final Rule, 187 FERC ¶ 61,068 at PP 1106–1107, 1126, 1145. Specifically, the final rule requires transmission providers to evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where, *inter alia,* ''an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million.'' *Id.* P 1145 (emphasis in original).

resources. For example, the final rule asserts that reforms are necessary because ''it may be more efficient or cost-effective to address [interconnection-related transmission needs] through the regional transmission planning and cost allocation process.'' [252] The final rule professes that its requirements ''will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation).'' [253] But more efficient or cost-effective for whom? Certainly not for consumers who will be conscripted to subsidize tens or hundreds of millions of dollars of interconnection costs so that generator developers may more cheaply interconnect and make higher profits (and likely receive government subsidies). The final rule's speculation that extracting such subsidies from consumers will ''facilitate access to lower-cost generation'' is purely pretextual.

106. The final rule notes that ''the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer.'' [254] Further, it asserts that the regional transmission facilities designed to address the interconnection needs ''may have the potential to provide more widespread benefits to transmission customers.'' [255] Today's final rule does not even come close to justifying the enormous cost shifts this will place on consumers.

107. The final rule summarily brushes aside the concern that its reform will shift interconnection costs from interconnection customers (*i.e.,* generation developers) to load.[256] It explains that ''[t]ransmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply.'' [257] The final rule also explains that ''if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits.'' [258] But the regional cost allocation methods allocate cost only to load, not to generation. So, how could allocating interconnection costs to load enable them to be ''roughly commensurate to benefits'' when generator developers, the primary beneficiaries of the transmission facilities and *the* ''*but for*'' *cause* of their development be allocated nothing? Here, as elsewhere, the final rule deviates from the FPA's consumer protection purpose: under the final rule, rather than generation existing to serve load, load is being conscripted to serve (the profits) of generation.

108. Finally, the final rule's conclusion that it will not incentivize gaming by interconnection customers to include interconnection-related network upgrades in the regional transmission planning process is detached from reality.[259] The final rule notes that interconnection requests require significant financial commitments from the interconnection customer (*e.g.,* application fees, study deposits, and site control requirements) and that interconnection customers employing such a strategy would face several risks.[260] As with so much FERC does, today's final rule woefully underestimates at its peril the profit-seeking, and at times, gambling behavior of generator developers. In issuing this final rule, the Commission appears to forget that a main driver in issuing Order No. 2023 was to *reduce* speculative interconnection requests and interconnection request withdrawals spurred by this behavior.[261] Despite the significant financial commitments and risks that the final rule describes, I can foresee generators submitting speculative or spurious interconnection requests in the efforts to be subsidized by load if the estimated interconnection costs are high enough. In any event, I think it obvious that, *ceteris paribus,* the final rule will encourage more disruptive *withdrawals*—particularly for requests that necessitate high interconnection costs—as the final rule provides generator developers dissatisfied with high interconnection costs a chance at another bite at the apple. And of course, apples taste sweeter when they're paid for by someone else.

ii. Factor Category Six Will Result in Unlawful Cost Shifts to Consumers

109. For similar reasons, I oppose the final rule's requirement that transmission providers in each transmission planning region incorporate in the development of Long-Term Scenarios, Factor Category Six: interconnection requests and withdrawals.[262] Such a requirement would ultimately result in consumers paying for the transmission that generators need to interconnect to the grid. This again is a way to cost shift interconnection costs from generation developers to consumers.

b. Factor Category Seven Forces Some Consumers To Subsidize Others

110. The Commission's requirement that transmission providers incorporate Factor Category Seven, utility and corporate commitments and federal, federally-recognized Tribal, state, and local goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios [263] is unjust and unreasonable because it will unfairly saddle consumers with unnecessary transmission costs that they *did not cause.* In addition, comments on Factor Category Seven identify several additional regulatory and practical obstacles that the final rule attempts to resolve by allowing transmission providers to dial the impact of these commitments and goals up or down.[264] Further, this provision is yet another count in the final rule's pattern of diminishing the states' role in regional transmission planning by elevating mere *corporate preferences* to have equal if not greater stature as the policy choices of states and federally-recognized Tribes.

111. It is worth starting the examination of Factor Category Seven simply by pulling the curtain back and highlighting the coalitions of comments that the final rule cites supporting it and opposed to it.[265] The strongest support for this provision comes from where we would all expect: the corporate interests with something to gain by shifting the costs that result from their preferential power purchase commitments to others along with the other special interests whose policy preferences have no place in developing a rate that is just and reasonable.[266] I am similarly unsurprised that the skeptics and opponents of this provision are led by retail rate authorities, load-serving entities from coast to coast, and large multi-state RTOs. They understand that adopting Factor Category Seven is unfair, unworkable, and a mistake.

112. Factor Category Seven is as unlawful as it is unfair because it grossly violates cost causation principles of ratemaking.[267] Whether a corporate commitment or a state/Tribal policy goal is directly attributed to increased transmission costs, the entities

[252] *Id.* P 1110.

[253] *Id.*

[254] *Id.* (footnote omitted).

[255] *Id.* PP 1146–1148.

[256] *See id.* P 1117.

[257] *Id.*

[258] *Id.; see also id.* P 1110.

[259] *See id.* PP 1119–1120.

[260] *Id.* P 1119.

[261] *See, e.g.,* Order No. 2023, 184 FERC ¶ 61,054 at P 47 (stating that the existing serial first-come, first-served study process ''create[d] incentives for interconnection customers to submit exploratory or speculative interconnection requests pursuant to which interconnection customers seek to secure valuable queue positions as early as possible, even if they are not prepared to move forward with the proposed generating facility. Such generating facilities are often not commercially viable and, thus, the interconnection customers ultimately withdraw from the interconnection queue.'').

[262] *See* Final Rule, 187 FERC ¶ 61,068 at P 472.

[263] *Id.* PP 481–484.

[264] *Id.* P 484.

[265] Commenters in favor include ACEG, AEE, Advanced Energy Buyers, Amazon, Breakthrough Energy, Center for Biological Diversity, Environmental Groups, Ørsted, PIOs, SEIA, and SREA. *Id.* PP 474–476. Commenters expressing qualified support include LADWP, MISO, and NRECA. *Id.* P 477. Commenters opposed include the Alabama Commission, California Commission, Duke, Illinois Commission, New York TOs, Pennsylvania Commission, PJM, and PPL. *Id.* PP 478–480.

[266] *See* James Downing, *FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming,* RTO Insider, Apr. 22, 2024 (''State renewable portfolio standards are not driving as much of the need for new transmission as the corporate renewable energy buyers that [Clean Energy Buyers] represents are, [Clean Energy Buyers Senior Director Bryn Baker] added.''), *https://www.rtoinsider.com/76831-ferc-experts-what-at-stake-transmission-rule-looming/.*

[267] For a reminder on the shell game and how it seeks to use the cost causation principle, *see supra* Sections I, III.A, IV.B.2.b.

with the self-imposed aspirations are the direct beneficiaries. Cost causation principles of ratemaking—not to mention reviewing courts—will dictate that those entities, and not any other transmission customer, are the beneficiaries of the resulting transmission built to accommodate the corporate commitments. As the direct beneficiaries, they will be responsible for the increased transmission costs driven by those commitments, goals, and preferences. Even worse, if one of these cost causers changes its commitment or goal, all of the transmission provider's customers could still be left paying for the increased costs that are *no longer attributable to any beneficiary.* This is not how a just or reasonable rate works.

113. Even if the unfair and unlawful Factor Category Seven is allowed to take effect, it will fail on its own terms for practical reasons. The final rule acknowledges that the corporate commitment or a state/Tribal policy goal are ''more likely to change over the transmission planning horizon than factors in other required factor categories.'' [268] As a balm for this uncertainty, the final rule grants the transmission providers the discretion to apply the salve of a discount on the likelihood that any of these aspirations will come to pass. Nothing in the final rule will prevent transmission providers from discounting these commitments one hundred percent. This discount is simply an invitation for transmission providers to ignore Factor Category Seven.

114. Even worse, when a transmission provider expends its limited resources to read the tea leaves of corporate commitments and include them in the Long-Term Scenarios, that inclusion will result in a violation of the FPA. Applying the costs of one corporation's commitments to all of the transmission provider's customers amounts to undue discrimination against similarly situated customers *without* corporate commitments while bestowing an undue preference for those similarly situated customers *with* corporate commitments. Further, most utility customers are at a resource and access disadvantage to the deep-pocketed special interests (including the corporate commitments driven by their wealthy and sophisticated investor class) that enjoy influence and power. Rather than sticking the consumers with any part of the bill for the gold plating necessary for a different customer's corporate preferences, this Commission should not depart from its cost allocation precedent. Under that precedent, the beneficiaries are required to pay for the upgrades they are driving. This Commission should not now saddle less powerful people and small businesses with the costs of the choices made by influential corporations and their managers and investors.[269]

115. Let me be clear about how egregious and unfair this idea is with a hypothetical scenario. Suppose that a Fortune 500 company pressured by its investors commits to a corporate goal that it will only purchase electric power from certain preferred generation sources within a decade. It similarly commits to discriminate against power sourced from non-preferred generation resources. The transmission provider then informs the corporate customer that transmission upgrades will be necessary in order for those favored generation resources to actually deliver power to the corporate customer's facilities and to avoid receiving power from the non-preferred resources. Next, the transmission provider includes those upgrades in Factor Category Seven. Later, the transmission provider builds the necessary upgrades according to its regional transmission plan and incurs significant cost in doing so. Instead of attributing those costs to the corporate customer, the transmission provider socializes the upgrade costs to *all* of its customers. Rather than holding the actual cost causer accountable for the increase, the final rule instead dictates that the costs directly resulting from the customer's corporate commitment benefit *all ratepayers* because there are necessarily reliability and economic benefits that result from all transmission development. Then these increased costs are socialized across all of the transmission provider's customers. This realistic outcome is, to put it mildly, grossly unfair to consumers and a violation of the FPA.

116. Now suppose that a neighboring corporate customer (that receives an identical class of electric service as the customer in the prior hypothetical) announces in response its own corporate goal that it will never consider any factors other than reliability and cost in purchasing electric power because it wants to keep its costs as low as possible no matter what. How is a transmission provider supposed to accommodate that second corporate goal? Do the two commitments simply cancel each other out? Will the transmission provider carve out the second corporate customer? Where would that leave the customers who are silent with respect to these competing corporate goals? The final rule fails to answer these questions.

c. The Final Rule Walks Back the NOPR Proposal To Remove the CWIP Incentive

117. Today's final rule also walks back the widely supported proposal to remove the CWIP transmission incentive. As I have discussed above, it is apparent that the pretextual goal of this final rule is to get transmission built to serve political and corporate goals, no matter the cost and no matter who actually benefits from it.

118. As I noted on numerous occasions, a core principle of utility law and regulation for decades is that consumers can be forced to pay costs only for assets that are ''used and useful'' to them. In Order No. 679, the Commission determined that it may be necessary to depart from this long-standing ratemaking principle to ''address the substantial challenges and risks in constructing new transmission.'' [270] And in my prior statements, I questioned, among other concerns, whether the Commission's determination of whether ''substantial challenges and risks'' exist when granting the various transmission incentives has becoming nothing more than a check-the-box exercise.[271] In particular, I noted:

The Commission's incentive policies—particularly the CWIP Incentive, which allows recovery of costs *before* a project has been put into service—run the risk of making consumers ''the bank'' for the transmission developer; but, unlike a real bank, which gets to charge interest for the money it loans, under our existing incentives policies the consumer not only effectively ''loans'' the money through the formula rates mechanism, but also pays the utility a profit, known as Return on Equity, or ''ROE,'' for the privilege of serving as the utility's *de facto* lender.[272]

119. The proposal to remove the CWIP Incentive was a major reason why I supported the NOPR, despite its flaws, and a massive step in the right direction to remedy the harm to consumers that these incentives have caused over the years.[273] However, instead of adopting the proposal to remove the CWIP Incentive, today's final rule chose to side with developers and special interest groups, rather than with consumers. Today's final rule rationalizes the decision to walk back the removal of the CWIP Incentive by finding that any action on the CWIP Incentive is more appropriately considered in a separate proceeding where incentives can be comprehensively evaluated for all regional transmission facilities.[274] I regard that as nothing more than an excuse for a continuing failure to act.

120. Many commenters share my concerns that the CWIP Incentive inappropriately shifts risks to ratepayers and runs afoul of the core principle of utility law and regulation that consumers should pay costs only for assets that are ''used and useful'' to them.[275] Others argue that removing the CWIP Incentive may mitigate the risk of

[268] Final Rule, 187 FERC ¶ 61,068 at P 484.

[269] I also have grave concerns that the final rule tasks transmission planning engineers to try their hands at becoming Wall Street analysts when they attempt to guess how serious any of the corporate commitments really are.

[270] *Promoting Transmission Inv. through Pricing Reform,* Order No. 679, 116 FERC ¶ 61,057, at PP 26, 117, *order on reh'g,* Order No. 679–A, 117 FERC ¶ 61,345 (2006), *order on reh'g,* 119 FERC ¶ 61,062 (2007).

[271] *See supra* n.61.

[272] February 2022 Concurrence at P 3 (emphasis in original); July 2022 Concurrence at P 3 (citation omitted); *see also* NOPR Concurrence at P 15 (''CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer . . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does.''), *https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-e-1-regional-transmission-planning-and-cost.*

[273] *See supra* PP 18–19.

[274] Final Rule, 187 FERC ¶ 61,068 at P 1547.

[275] *See, e.g.,* California Commission Reply Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4–9; NARUC Initial Comments at 55–56 (referencing PATH and that the Commission granted several transmission incentives, resulting in a 14.3% return on equity); NASUCA Initial Comments at 8–9; North Carolina Commission and Staff Initial Comments at 17–18; North Dakota Commission Initial Comments at 6; Ohio Commission Federal Advocate Initial Comments at 15–16; Ohio Consumers Initial Comments at 29–31; OMS Initial Comments at 14–15; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13; Virginia Attorney General Reply Comments at 3–4.

overbuilding that may result from the other changes cemented in today's final rule.[276] Today's final rule, however, is astoundingly silent on the consumer impact of retaining the CWIP Incentive.

121. Unfortunately, this is simply a continuation of the Commission punting on any meaningful reevaluation of transmission incentives. In my three years on the Commission, there has been *no* action to reevaluate the check-the-box award of transmission incentives, and it is far past time for me to begin dissenting from this lack of action on the Commission's part to change this shameful status quo.[277] By walking back the removal of the CWIP Incentive, today's final rule reveals, one again, its failure to protect consumers as required by the FPA.

V. Conclusion

122. Had the states been given the authority to protect their consumers, as promised by the NOPR, I would have supported this rule just as I voted for the NOPR, as an imperfect but acceptable compromise.[278] If transmission projects that are planned to implement public policies—the product of *political* decisions made by politicians—or to implement corporate ''green energy'' power purchasing preferences—the product of corporate management and investors—are going to be included in long-term planning *mandated* by FERC, then the states must have the authority to consent to (i) the planning criteria (which determines which projects go into regional plans and receive cost recovery from consumers), *and* (ii) the formula for regional cost allocation of such projects.

123. This role for the states is not only essential but fair: fair to state policymakers and regulators and fair to the tens of millions of consumers they represent. The final rule, however, denies states that essential role and that denial renders this order unfair to the states and unfair to tens of millions of consumers.

124. As has been said before, denial is not just a river in Egypt. The short-sightedness of the final rule and the special interests who lobbied this Commission to deny states this key role is a denial of the reality of how transmission actually gets built in the union of states that is the United States of America. As a former state regulator who voted to approve scores of transmission projects, both regional and local, I will testify from experience that to get transmission built—especially the big, controversial regional lines of 500 kV and above—the states should not be dismissed as annoying obstacles that must be pushed out of the way by an omnipotent, omniscient FERC. Rather, state regulators must be respected as potential partners and, most importantly, *advocates* of such controversial lines, who will be invested in them and work to get them sited and built within their borders. That will never happen if states are denied the role that I advocated in the NOPR, that of full partners in deciding how, when and whether their consumers are burdened with costs for politically and corporate-driven policy projects.

125. This final rule could have corrected the single biggest flaw in Order No. 1000: the exclusion of the states from decision-making roles in FERC-mandated regional transmission planning for public policy projects. Instead, the final rule doubles down on that error with a blizzard of new planning mandates to serve political, corporate, and ideological agendas, while leaving the states with no real power to protect their consumers from the trillions of dollars of costs that this order brazenly wants to impose on them. The final rule is nothing but a pretext for enacting a sweeping policy agenda that Congress never passed. As such, it blatantly violates the major questions doctrine. In producing rates that will be unjust, unreasonable, and unduly discriminatory and preferential, it violates the actual text of the FPA. And in that violation, it fails to fulfill our most important duty under the FPA, which is to protect consumers.

For these many reasons, I respectfully dissent.

Mark C. Christie
Commissioner

[276] *See, e.g.,* Massachusetts Attorney General Initial Comments at 24–25; North Carolina Commission and Staff Initial Comments at 17–18; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13.

[277] *See, e.g., Baltimore Gas & Elec. Co.,* 187 FERC ¶ 61,030 (Christie, Comm'r, dissenting at P 6).

[278] To reiterate what I said earlier: If I agree to get a root canal with anesthetic but learn upon arrival at the dentist's office that I still get the root canal but no anesthetic, that is not the original deal.

[FR Doc. 2024–10872 Filed 6–10–24; 8:45 am]
BILLING CODE 6717–01–P