DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM21–17–001; Order No. 1920–A]

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

AGENCY: Federal Energy Regulatory Commission, Department of Energy (DOE).

ACTION: Order on rehearing and clarification.

SUMMARY: In this order, the Federal Energy Regulatory Commission addresses arguments raised on rehearing, sets aside, in part, and clarifies Order No. 1920, which required transmission providers to conduct Long-Term Regional Transmission Planning to 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. Order No. 1920 also directed 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.

DATES: The changes to Order No. 1920 made in this order on rehearing and clarification will be effective on January 6, 2025.

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SUPPLEMENTARY INFORMATION:

I. Executive Summary

1. In Order No. 1920,[1] the Federal Energy Regulatory Commission (Commission) revised the *pro forma* Open Access Transmission Tariff (OATT) to adopt reforms to its existing electric transmission planning and cost allocation requirements pursuant to section 206 of the Federal Power Act (FPA).[2] The Commission found that existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because, *inter alia,* 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;[3] (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider a set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[4] Order No. 1920 addressed these deficiencies by establishing requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential including, *inter alia,* requiring transmission providers to conduct Long-Term Regional Transmission Planning[5] that will ensure the identification, evaluation, and selection of more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs, as well as the just and reasonable allocation of the costs of those facilities. By expanding the time horizon and scope of Commission-jurisdictional regional transmission planning processes, Order No. 1920 reflected an evolutionary step in the Commission's ongoing commitment[6] to ensure that those

[1] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation,* Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068 (2024).

[2] 16 U.S.C. 824e.

[3] *See infra* Introduction and Background section (defining ''Long-Term Transmission Needs'').

[4] Order No. 1920, 187 FERC ¶ 61,068 at P 1.

[5] *See infra* Introduction and Background section (defining ''Long-Term Regional Transmission Planning).

[6] *See 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); *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.*

processes remain just and reasonable and meet the needs of the American people.

2. In this order, we refine and improve Long-Term Regional Transmission Planning by building on the reforms adopted in Order No. 1920, with a particular focus on ensuring that states have a robust role in Long-Term Regional Transmission Planning and cost allocation processes established in this rule. We continue to find, as the Commission did in the final rule, that the key components of Order No. 1920 together ensure that transmission providers will conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes. At least once every five years, transmission providers are required to conduct Long-Term Regional Transmission Planning, a process that includes looking ahead over a 20-year transmission planning horizon. This process further requires developing at least three plausible and diverse Long-Term Scenarios [7] that are based upon known drivers of transmission needs and informed by best available data; analyzing the impacts of events like extreme weather under each Long-Term Scenario; and evaluating potential Long-Term Regional Transmission Facilities.[8] This evaluation includes assessing whether these facilities would yield reliability and economic benefits to transmission customers and, if so, identifying those benefits. Together, these reforms ensure that transmission providers, state regulators, and stakeholders possess the information necessary for each transmission planning region to identify, evaluate, and select (*i.e.,* determine whether to pursue the development of facilities) more efficient or cost-effective transmission facilities that provide significant benefits for customers.

3. Here, we adopt a number of modifications and clarifications to address the concerns raised in response to Order No. 1920. Order No. 1920 recognized the important role that states will play in Long-Term Regional Transmission Planning and established various requirements to facilitate their participation in those processes, including requiring transmission providers to engage with states in developing cost allocation approaches for Long-Term Regional Transmission Facilities. With this order, we reaffirm and enhance that finding by recognizing that meaningful engagement with states is critical to the success of the Long-Term Regional Transmission Planning reforms established in Order No. 1920. Specifically, in response to rehearing and clarification requests, we better integrate states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. These modifications and clarifications address many of the concerns raised in the rehearing requests submitted in response to Order No. 1920, and they will increase the likelihood that Long-Term Regional Transmission Planning results in efficient and cost-effective transmission investment.

4. In this order, we also clarify what this rule does, and does not, require. Because Order No. 1920 mandates only improvements to transmission planning *processes* which, in turn, ensures foundational transparency about potential transmission development, Order No. 1920 does not force or mandate the development of certain transmission facilities. A requirement to develop a structured process to analyze *whether* building certain transmission facilities would yield benefits greater than their costs, over the long term and based upon various future scenarios, will help transmission providers and states to assess the value that those projects could bring. However, such process-based requirements are not the same as a requirement to build any particular transmission facilities. More precisely, Order No. 1920 does not require transmission providers to select any particular transmission facility; does not automatically authorize transmission developers to develop or construct any specific facilities; and does not mandate any specific set of transmission customers to pay for any particular transmission facilities. Instead, Order No. 1920 and this order together set out processes that direct transmission planning regions to systematically consider various drivers of transmission needs and develop cost allocation approaches that yield the development of cost-effective transmission projects and thereby yield just and reasonable rates for customers.

5. As such, Long-Term Regional Transmission Planning as required by Order No. 1920 is a significant step forward in the Commission's responsibility to ensure just and reasonable and not unduly discriminatory or preferential rates. By establishing minimum standards based on transmission planning best practices observed around the country for forecasting future scenarios and managing the uncertainty inherent in forward-looking planning, the Long-Term Regional Transmission Planning requirements established in this proceeding will lead transmission providers to re-direct investment toward more efficient or cost-effective regional transmission facilities, and ultimately produce greater benefits for transmission customers.

6. Moreover, improving regional transmission planning practices is an urgent concern in light of the uncontroverted, rapidly changing circumstances on the grid, including load growth; the increased impacts of extreme weather; affordability concerns; and changing economics and policies that shape the resource mix and demand, which are increasing the need for transmission across the country. To cost-effectively meet these needs, Order No. 1920 and this order set out systematic processes that transmission providers will use to identify and analyze transmission projects that bring benefits to consumers, while recognizing the need for flexibility to account for regional differences.

7. Order No. 1920 follows in the footsteps of Order Nos. 890 and 1000 when it comes to the requirements governing the selection of potential regional transmission facilities identified through Long-Term Regional Transmission Planning. Consistent with the core theory of Order Nos. 890 and 1000, even though Order No. 1920 does not require the buildout of specific transmission facilities, it will reveal the benefits of designing and developing transmission projects and enable investment in those that yield great benefits for electricity customers across the country. Ultimately, we expect Order No. 1920 to lead to the development of more efficient or cost-effective transmission facilities through improved analysis and transparency that empower the transmission planning regions with the information needed to make prudent investments in beneficial transmission infrastructure for customers.

8. Order No. 1920's requirements for regional cost allocation practices are similarly well grounded in Commission and court precedent. If more efficient or cost-effective Long-Term Regional Transmission Facilities are identified and determined to be worth developing as a result of the enhanced regional transmission planning required by Order No. 1920, customers will pay for these facilities *only to the extent that*

S.C. Pub. Serv. Auth. v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

[7] *See infra* Introduction and Background section (defining ''Long-Term Scenario'').

[8] *See infra* Introduction and Background section (defining ''Long-Term Regional Transmission Facility'').

they benefit from them. That is because Order No. 1920 requires, consistent with well-established law and Orders No. 890 and 1000, that any cost allocation must comply with cost causation and the ''beneficiary pays'' principle.[9] Thus, Order No. 1920 will not lead one group of customers to pay for more than their fair share of the costs of transmission development because any proposal to charge customers for costs that are not ''roughly commensurate'' with the benefits they are expected to receive from Long-Term Regional Transmission Facilities would contravene the final rule.[10]

9. Order No. 1920 builds on Order No. 1000's cost allocation requirements. Order No. 1000 required transmission providers to incorporate into their tariffs a default (''*ex ante*'') cost allocation approach that, *if* transmission facilities are determined to be worth investing in based upon the results of the regional transmission planning process, would provide a mechanism for those transmission customers that benefit to pay for those projects. Prior to Order No. 1000, transmission providers did not necessarily have the means to charge transmission customers located within a particular transmission planning region, but outside their individual service territories, for the costs of regional transmission facilities that benefit customers throughout the region. Thus, the requirement to establish an *ex ante* cost allocation method in each OATT that would apply if a regional transmission planning process resulted in the selection of more efficient or cost-effective transmission facilities was central to ensuring that those facilities could actually be developed. Like Order No. 1000, Order No. 1920 requires each transmission provider to establish at least one *ex ante* cost allocation method through which the costs of Long-Term Regional Transmission Facilities will be allocated in a manner consistent with the ''beneficiary pays'' principle. Just like in Order No. 1000, the requirement to establish a mechanism by which the costs of selected transmission facilities may be allocated to relevant benefitting transmission customers does not mandate any particular method that transmission providers or planning regions must adopt.

10. Importantly, Order No. 1920 provides *additional flexibility* to transmission providers and states regarding cost allocation. While transmission providers under Order No. 1000 must adopt a cost allocation method for each type of transmission facility, Order No. 1920 relaxes this requirement. Furthermore, the modifications and clarifications granted on rehearing expand states' critical role in determining the cost allocation approach most suitable for each transmission planning region. These modifications and clarifications are necessary because the Commission recognizes that states play a critical role in the successful planning of, the decision about how to pay for, and ultimately, the deployment of beneficial regional transmission facilities.

11. For example, under Order No. 1920 as modified in this order, Relevant State Entities have an opportunity to negotiate their preferred *ex ante* cost allocation method(s) in the first instance, including being able to secure an extension of time if needed to continue those negotiations. Upon reaching agreement, Relevant State Entities can present their preferred approach to the transmission provider, which then will either propose that approach to the Commission in its compliance filing for this rule, or if the transmission provider submits a different proposal, will include in its compliance filing the states' preferred approach for the Commission to consider.

12. This order further improves states' ability to negotiate cost allocation methods. Under Order No. 1920, states, through Relevant State Entities,[11] have an opportunity to secure the right to negotiate alternate cost allocation methods in the future, for either an individual transmission facility or a group of them, instead of using the *ex ante* cost allocation method on file in transmission providers' OATTs. This State Agreement Process [12] allows Relevant State Entities to consider, for example, whether certain Long-Term Regional Transmission Facilities largely provide a unique set of benefits such that the costs of those facilities are appropriately paid for in a different manner than under the *ex ante* cost allocation method. And, going forward, we require transmission providers to consult with Relevant State Entities regarding potential future changes to *ex ante* cost allocation methods and State Agreement Processes used in Long-Term Regional Transmission Planning.

13. Order No. 1920 provides greater flexibility than Order No. 1000 to deviate from the *ex ante* cost allocation method or to establish more than one *ex ante* cost allocation method. We also provide new opportunities for states to influence each of these choices because better enabling state input into cost allocation choices helps to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities that are likely to be sited and constructed only with state regulatory approval are ultimately developed successfully. Given that Order No. 1920 continues to afford considerable flexibility to transmission providers and Relevant State Entities to determine the cost allocation methods appropriate for their transmission planning region and retains the core obligation that any cost allocation method filed must be consistent with cost causation, the beneficiary pays principle, and other statutory requirements, we believe that cost allocation under this rule will result in just and reasonable rates. Order No. 1920 requires no more than Order No. 1000—that some mechanism for charging customers for more efficient or cost-effective transmission facilities be available in case such facilities are determined, after evaluation through Long-Term Regional Transmission Planning, to be worth developing. In fact, Order No. 1920 expands the opportunities for transmission providers, state regulators, and stakeholders to ensure that the costs of Long-Term Regional Transmission Facilities are allocated only ''roughly commensurate'' with the benefits expected to result from those facilities.

14. As noted above, we agree with certain arguments raised on rehearing and/or clarification of Order No. 1920. The instances where we modify the discussion in Order No. 1920 and set aside the result of Order No. 1920 generally fall into three categories. First, as discussed above, we further enhance the role of Relevant State Entities in Long-Term Regional Transmission Planning, especially their role in shaping the development of Long-Term Scenarios and cost allocation methods. Second, we clarify that, when Relevant State Entities request, transmission providers must develop a reasonable

[9] *See PJM Interconnection, L.L.C.,* Opinion No. 494, 119 FERC ¶ 61,063, at P 66 (2007) (requiring PJM to set forth a ''beneficiary pays'' method in its tariff and consistently apply that approach each time a new regionally-planned transmission facility is approved), *on reh'g,* Opinion No. 494–A, 122 FERC ¶ 61,082 (2008), *remanded Ill. Com. Comm'n* v. *FERC,* 576 F.3d 470, 474–78 (7th Cir. 2009) (*ICC* v. *FERC I*) (remanding Commission order for further proceedings in light of Commission's failure to provide substantial evidence supporting Commission's approval of cost allocation method as complying with ''beneficiary pays'' principle).

[10] *See ICC* v. *FERC I,* 576 F.3d at 477 (holding that, if the Commission cannot quantify the benefits of particular transmission facilities to a particular class of transmission customers, it must have ''an articulable and plausible reason to believe that the benefits [of those facilities] are at least roughly commensurate with'' the costs to be paid by those customers).

[11] *See infra* Introduction and Background section (defining ''Relevant State Entity'').

[12] *See infra* Introduction and Background section (defining ''State Agreement Process'').

number of additional scenarios to help inform the development or application of cost allocation methods. And third, we remove the requirement that transmission providers include corporate commitments in Factor Category Seven.

15. In the first category, Order No. 1920 provided an opportunity for states to influence how transmission is planned and ultimately paid for. This order goes even farther by agreeing with the rehearing arguments advanced by several states seeking additional and expanded opportunities for states to engage. Specifically, we require transmission providers to incorporate input from states about how Long-Term Scenarios used in Long-Term Regional Transmission Planning will be developed, particularly given that these scenarios will necessarily reflect how the states plan to meet their laws, policies, and regulations. In addition, we require transmission providers to include in the transmittal or as an attachment to their Order No. 1920 compliance filings any *ex ante* cost allocation method and/or State Agreement Process agreed to by the Relevant State Entities (to the extent the transmission provider does not adopt such an agreed-to cost allocation method and/or process as its own proposal), along with any information related to the Engagement Period [13] requested by a Relevant State Entity to be included. We are further persuaded by arguments on rehearing that Relevant State Entities may, in some cases, need time beyond the six-month Engagement Period allowed under Order No. 1920. We therefore clarify that the Commission will grant extensions of time requested by Relevant State Entities where there is a showing that additional time is needed to resolve cost allocation discussions, up to a period of an additional six months. We believe this clarification ensures states who are engaged in working toward agreed-upon cost allocation methods and/or a State Agreement Process will have the time they need to resolve those discussions.

16. Furthermore, to ensure that Relevant State Entities have a role in cost allocation for Long-Term Regional Transmission Facilities going forward, we require that transmission providers consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, to amend that method or process. Finally, we clarify that the flexibility Order No. 1920 affords to transmission providers and Relevant State Entities to determine cost allocation methods appropriate for their region does not preclude proposed methods that allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation, *e.g.,* based on the incremental costs and benefits of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations.

17. In the second category, we clarify in response to requests for rehearing that, while transmission providers are obligated to develop three Long-Term Scenarios that meet all of the requirements of the rule, Order No. 1920 permits transmission providers to develop additional analyses, including other scenarios, to help inform who pays for those selected facilities. We further modify Order No. 1920 on rehearing to now require that transmission providers develop a reasonable number of additional scenarios at Relevant State Entities' request. The aim of Order No. 1920 is to ensure that transmission providers engage in the sufficiently long-term, forward-looking, and comprehensive transmission planning that is essential to have the information necessary to determine which investments are worth making. As long as transmission providers engage in that robust planning process and achieve the transparency required through that process, transmission providers can develop and consider additional information beyond that required as part of Long-Term Regional Transmission Planning.

18. In the third category of changes, on rehearing we modify, in one respect, the requirement to use seven categories of factors in the development of the three Long-Term Scenarios that are used to identify Long-Term Transmission Needs, and potential solutions to those needs. Several parties raise concerns regarding the inclusion of corporate commitments in Factor Category Seven, which they argue may elevate the needs of particular transmission customers above those of others. Upon further consideration, we eliminate the requirement to incorporate corporate commitments from Factor Category Seven into each Long-Term Scenario and thus we eliminate the potential for confusion around the treatment of particular transmission customers, while enabling transmission providers to give appropriate weight to corporate commitments as an indicator of customer preference in a region where those preferences are known.

19. Taken together, we believe the requirements of Order No. 1920 with the modifications and clarifications we make on rehearing will remedy the deficiencies of current regional transmission planning processes, establish sufficiently long-term, forward-looking, and comprehensive transmission planning, and ensure that transmission providers and Relevant State Entities in each region have the flexibility to devise cost allocation methods that reasonably and fairly assign the costs of Long-Term Regional Transmission Facilities to those that benefit from such facilities.

II. Introduction and Background

20. In Order No. 1920, the Commission found that 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: [14] (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; [15] (2)

[13] *See infra* Introduction and Background section (defining ''Engagement Period'').

[14] 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) (*TAPS*), *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).

[15] For purposes of Order No. 1920, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in Order No. 1920, running scenarios and considering the enumerated categories of factors. Order No. 1920, 187 FERC ¶ 61,068 at P 299.

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.[16]

21. Order No. 1920 therefore established requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. First, Order No. 1920 required transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[17] Order No. 1920 established specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning, including, among other things, the use of Long-Term Scenarios to identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities [18] to meet those needs.[19]

22. Order No. 1920 required transmission providers to measure and use at least seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning.[20] Order No. 1920 required 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 required 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.[21]

23. Order No. 1920 required 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.[22] Further, Order No. 1920 required transmission providers to include in their OATTs a process to provide Relevant State Entities [23] 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 transmission providers' selection criteria.[24] Order No. 1920 also required 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.[25]

24. Order No. 1920 required transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods [26] to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected.[27] Order No. 1920 further allowed, but did not require, transmission providers to adopt a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities.[28] Where Relevant State Entities agree to such a State Agreement Process, and transmission providers choose to file such a process, a State Agreement Process would provide Relevant State Entities 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.[29] Order No. 1920 also established 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.[30]

25. Order No. 1920 required transmission providers to 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 originally identified through the generator interconnection process.[31]

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[16] Order No. 1920, 187 FERC ¶ 61,068 at P 1.

[17] *Id.* P 224. 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. *Id.* For purposes of Order No. 1920, 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. *Id.* P 2 n.7; *see* Order No. 1000, 136 FERC ¶ 61,051 at P 160.

[18] For purposes of Order No. 1920, a Long-Term Regional Transmission Facility is a regional transmission facility that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs. Order No. 1920, 187 FERC ¶ 61,068 at P 250. For the purposes of Order No. 1920, 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. *Id.* P 41 n.58 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 482 n.374).

[19] *Id.* P 298. For purposes of Order No. 1920, 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. *Id.* P 302.

[20] *Id.* P 719.

[21] *Id.* P 859. The Commission recognized 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. *Id.* P 3 n.8 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 63). For purposes of Order No. 1920, unless otherwise noted, when referencing Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected, we intend that the word ''selected'' mean that those Facilities are selected in the regional transmission plan for purposes of cost allocation. *Id.*

[22] *Id.* P 911.

[23] For the purposes of Order No. 1920, 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. *Id.* P 1355.

[24] *Id.* P 1012.

[25] *Id.* P 1048.

[26] For purposes of Order No. 1920, a Long-Term Regional Transmission Cost Allocation Method is 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. *Id.* P 1291.

[27] *Id.*

[28] *Id.* P 1402. For purposes of Order No. 1920, 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. *Id.*

[29] *Id.*

[30] *Id.* P 1354.

[31] *Id.* PP 1106–1107.

26. Order No. 1920 required transmission providers 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.[32]

27. Order No. 1920 required 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.[33]

28. Order No. 1920 required transmission providers to revise their interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in Order No. 1920.[34] Order No. 1920 also required transmission providers to meet additional information sharing and transparency requirements with respect to their interregional transmission coordination processes.[35]

29. The Commission received 49 timely filed requests for rehearing and/or clarification[36] and several additional filings.[37] The rehearing requests raise issues related to nearly all reforms adopted in Order No. 1920.

30. Pursuant to *Allegheny Defense Project* v. *FERC,*[38] the rehearing requests filed in this proceeding may be deemed denied by operation of law. However, as permitted by section 313(a) of the FPA,[39] we are modifying the discussion in Order No. 1920, setting aside the order, in part, and clarifying the order, as discussed below.[40]

31. Specifically, we set aside the order, in part, to specify that: (1) transmission providers are not required to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs;[41] (2) Factor Category Seven no longer includes corporate commitments;[42] (3) transmission providers must propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than two years from the date on which they will commence the first Long-Term Regional Transmission Planning cycle;[43] (4) when Relevant State Entities agree on a Long-Term Regional Transmission Cost Allocation Method or State Agreement Process resulting from the Engagement Period, transmission providers must include that method or process in the transmittal or as an attachment to their compliance filing, even if transmission providers propose a different Long-Term Regional Transmission Cost Allocation method or do not propose to adopt a State Agreement Process along with any information that Relevant State Entities provide to transmission providers regarding the state negotiations during the Engagement Period;[44] and (5) transmission providers shall consult with Relevant State Entities prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

32. Additionally, we grant multiple clarifications on most elements of Order No. 1920, as further discussed below. For example, among other clarifications, we clarify that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es), and that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion to those benefits.

33. Finally, we specify that the Commission will grant an extension of the required Engagement Period for up to an additional six months when Relevant State Entities request an extension and represent to the Commission that they agree, consistent with their chosen method to reach agreement, that they need additional time to finish cost allocation discussions. If the Commission grants such an extension request, it will also, as appropriate, extend, *sua sponte,* the relevant Order No. 1920 compliance deadlines to ensure that any extension of the Engagement Period would not conflict with the required compliance deadlines.

III. The Overall Need for Reform

A. Order No. 1920

34. In Order No. 1920, the Commission found substantial evidence to support the conclusion that the

[32] *Id.* P 1198.

[33] *Id.* PP 1625, 1677.

[34] *Id.* P 1751.

[35] *Id.*

[36] Appendix A provides the short names of the entities that filed requests for rehearing or clarification. To the extent that they intend to seek rehearing, the pleadings filed by Grid United, PJM States, Vermont Commission, and Virginia and North Carolina Commissions are deficient because they fail to include a separate section entitled ''Statement of Issues'' listing each issue presented to the Commission in a separately enumerated paragraph that includes representative precedent on which the participant is relying, as required by Rule 713(c)(2) of the Commission's Rules of Practice and Procedure (18 CFR 385.713(c)(2)). Consistent with Rule 713, we deem these petitioners to have waived the issues for which they seek rehearing. We consider petitioners' requests for clarification and, to provide clarity, address their arguments on rehearing below. EEI, PJM States, and PJM Utilities filed answers to certain requests for rehearing. Rule 713(d)(1) (18 CFR 385.713(d)(1)) prohibits an answer to a request for rehearing. Accordingly, we deny EEI's, PJM States', and PJM Utilities' motions to answer and reject their answers. Although PJM States style their July 3, 2024 pleading as comments, we treat the pleading as an answer to PJM's request for rehearing. *See, e.g., San Diego Gas & Elec. Co.,* 133 FERC ¶ 61,014, at P 15 (2010) (''[W]e are not obligated to accept a filing solely on the basis of its party-bestowed title. Instead, we examine the substance of the pleading.'').

[37] Susann Rizzo, Gary Andrews, and Cher Gilmore filed letters supporting Order No. 1920. They also urged the Commission to require interregional transmission planning and establish environmental justice liaisons. In addition, E. Andrews, Illinois Commission, and Minnesota Commission each submitted late-filed pleadings that are generally supportive of Order No. 1920. Further, on June 12, 2024, Missouri Commission filed a letter addressing Order No. 1920. On September 3, 2024, Chairman Willie Phillips responded to the Missouri Commission letter. On July 22, 2024, State Regulatory Commissioners filed a letter expressing views on Order No. 1920. On October 9, 2024, Chairman Willie Phillips responded to the State Regulatory Commissioners' letter.

[38] 964 F.3d 1 (D.C. Cir. 2020) (en banc).

[39] 16 U.S.C. 825*l*(a) (''Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.'').

[40] *Allegheny Def. Project,* 964 F.3d at 16–17. In Appendix B, we provide the revisions to the provisions of Attachment K to the *pro forma* OATT made in this order on rehearing and clarification.

[41] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 301 (''Transmission providers must use [the set of seven required benefits] to help to inform their identification of Long-Term Transmission Needs.'').

[42] *See id.* P 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.'').

[43] *See id.* P 1072 (''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 rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle.'').

[44] *See id.* P 1359 (''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.'').

Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential. Specifically, the Commission explained that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements causes transmission providers to fail to adequately anticipate and plan for future system conditions and to fail to appropriately evaluate the benefits of transmission infrastructure.[45] The Commission found that this status quo results in piecemeal transmission expansion to address relatively near-term needs and causes transmission providers to make relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. One result of this dynamic, the Commission explained, is that transmission customers overpay to meet their transmission needs and forgo benefits that outweigh their costs, which results in less efficient or cost-effective transmission investments. Such deficiencies, the Commission found, render Commission-jurisdictional regional transmission planning and cost allocation processes unjust, unreasonable, and unduly discriminatory or preferential.[46]

35. The Commission explained that it has the authority to issue Order No. 1920 under FPA section 206, which ''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.' ''[47] The Commission concluded that the D.C. Circuit has recognized that regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction[48] and that 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.[49] The Commission found that, because these processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates, they directly affect those rates.[50] The Commission found that, because such regional transmission facilities lead to a more robust transmission system, regional transmission planning and cost allocation processes, as well as ''the rules and practices that determine how those [processes] operate,''[51] directly affect rates that customers pay for *both* transmission and sale of electric energy in interstate commerce.[52] The Commission noted that it may act pursuant to FPA section 206 if the Commission first establishes, through substantial evidence,[53] that existing practices are unjust, unreasonable, or unduly discriminatory or preferential and, second, establishes that the replacement practices are just and reasonable.[54]

36. Addressing whether existing rates, or practices affecting rates, remain just and reasonable—*i.e.,* the first prong under FPA section 206[55]—the Commission found that existing Order No. 890 and Order No. 1000 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, and transmission providers therefore often do not identify, evaluate, or select more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs.[56] The Commission determined that this results in piecemeal, inefficient, and less cost-effective transmission planning, which imposes real costs on customers[57] and renders the Commission's existing transmission planning and cost allocation requirements unjust, unreasonable, and unduly discriminatory or preferential in violation of FPA section 206.[58]

37. The Commission also found that existing transmission planning and cost allocation requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates. Thus, pursuant to FPA section 206, the Commission stated that it is now requiring 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. The Commission found that such 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.[59]

1. The Transmission Investment Landscape Today

38. The Commission explained that due to continuing changes in the industry, ongoing investment in transmission facilities is necessary to ensure the transmission system remains reliable, affordable, and economically efficient. More comprehensive transmission planning can enable transmission providers to proactively identify potential reliability problems and economic constraints and evaluate potential transmission solutions, which can facilitate the selection of more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.[60] Transmission infrastructure can also increase competition among generators, which results in a host of benefits for customers, including cost savings from greater access to low-cost power.[61]

39. The Commission cited evidence demonstrating a nationwide increase in transmission spending since the issuance of Order No. 1000 and explained that, unsurprisingly, transmission costs have become an increasing share of customers' overall electricity bills in regions that saw a significant increase in transmission expenditures.[62] Further, the Commission highlighted several studies in the record demonstrating that

[45] Order No. 1920, 187 FERC ¶ 61,068 at P 85.

[46] *Id.*

[47] *Id.* P 86 (citation omitted) (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55).

[48] *Id.* (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55–59, 84).

[49] *Id.* (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56).

[50] *Id.; see also id.* P 86 n.186 (citing *Conn. Dep't of Pub. Util. Control* v. *FERC,* 569 F.3d 477, 485 (D.C. Cir. 2009)).

[51] *Id.* P 86 (quoting *FERC* v. *Elec. Power Supply Ass'n,* 577 U.S. 260, 279 (2016) (*EPSA*)).

[52] *Id.* (citing 16 U.S.C. 824e(a)).

[53] *Id.* (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 54). The Commission explained that FPA section 206 empowers the Commission to address the mere *threat* of unjust and unreasonable rates and, in this context the Commission need not necessarily provide *empirical* evidence for every proposition to satisfy the substantial evidence standard. Order No. 1920, 187 FERC ¶ 61,068 at P 86 n.189 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64–65, 85).

[54] *Id.* (citing 16 U.S.C. 824e(a); *EPSA,* 577 U.S. at 277).

[55] *See Pub. Serv. Elec. & Gas Co.* v. *FERC,* 989 F.3d 10, 13 (D.C. Cir. 2021) (explaining that section 206 ''mandates a two-step procedure'' whereby the Commission, on the first step, must make an explicit finding that the existing rate is unlawful and then, on the second step, must set a new rate. (quotation omitted)).

[56] Order No. 1920, 187 FERC ¶ 61,068 at P 87.

[57] *Id.*

[58] *Id.* P 88.

[59] *Id.* P 89.

[60] *Id.* P 90 (citations omitted).

[61] *Id.* P 91.

[62] *Id.* P 92 (citations omitted).

transmission investment is likely to increase substantially in coming years.[63]

40. The Commission found that a number of factors are driving the growing need for new transmission infrastructure.[64] First, the Commission found that longer-term reliability needs are changing and driving a significant shift in the demands placed on the transmission system, and transmission system operators are increasingly depending on regional transmission facilities to ensure operational stability and system reliability, particularly due to the growing frequency of extreme weather events and increasing share of variable resources entering the resource mix.[65] Second, after many years of flat or minimal load growth in regions across the country, the Commission found that both regional and national demand is projected to increase significantly in the coming decades, which will require an increasingly robust transmission system to serve this growing load reliably. Third, the Commission found that supply is changing, driven by federal, federally-recognized Tribal, state, and local policies, customer demands, utility commitments, and the shifting economics of resources that comprise the resource mix.[66]

41. The Commission also found that the record in this proceeding affirms the Commission's longstanding recognition that regional transmission planning that identifies more efficient or cost-effective transmission solutions helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions, while inadequate or poorly designed transmission planning processes can cause customers to foot the bill for piecemeal, inefficient, and less cost-effective transmission solutions.[67]

42. Based on its experience implementing Order No. 1000, the Commission found that existing regional transmission planning processes are not of sufficient scope and duration to adequately or consistently identify transmission needs and associated opportunities to evaluate and select, on a more comprehensive basis, more efficient or cost-effective transmission solutions to those needs.[68] The Commission explained that, in some regions, investment in regional transmission facilities has declined as compared to prior to Order No. 1000 and that, across all non-RTO/ISO regions, not a single transmission facility has been selected pursuant to the regional planning processes since implementation of Order No. 1000. The Commission noted that, within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process occur, much of that investment has been in transmission projects that only address immediate reliability needs.[69] The Commission also cited evidence showing that, in the limited instances in which transmission providers have followed processes that share many of the elements that Order No. 1920 requires, customers have seen clear and quantifiable benefits.[70]

43. Further, the Commission explained that a substantial amount of new transmission investment is occurring in generator interconnection processes and local transmission planning processes, which, unlike regional transmission planning processes, do not comprehensively assess either broader transmission needs or solutions to those needs. The Commission concluded that overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[71]

44. The Commission cited evidence showing 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, as well as evidence showing that increases in interconnection costs are being driven, in many cases, by an expansion in the scope and complexity of interconnection-related network upgrades.[72] The Commission noted that, unlike regional transmission planning processes, 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.[73] The Commission found 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.[74]

45. The Commission also cited evidence that, since the issuance of Order No. 1000, the majority of investment in transmission facilities has been in local transmission facilities, a trend that is accelerating across multiple regions.[75] The Commission noted evidence that transmission expansion through local transmission planning and in-kind replacement processes is incremental and misses the potential 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.[76] Such transmission planning, the Commission stated, results in relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.[77]

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

46. The Commission concluded that there is substantial evidence in the record 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.[78] The Commission found that the absence of a sufficiently long-term, forward-looking, and comprehensive regional transmission planning process results in relatively unfavorable outcomes, including: piecemeal transmission expansion to address relatively near-term transmission needs, transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, and transmission customers paying more than is necessary or appropriate to meet their transmission needs and/or

[63] *Id.* P 93 (citations omitted).

[64] *Id.* P 94 (citations omitted).

[65] *Id.* (citations omitted).

[66] *Id.* PP 96–99 (citations omitted).

[67] *Id.* P 100 (citations omitted).

[68] *Id.* P 101.

[69] *Id.* (citations omitted).

[70] *Id.* P 102.

[71] *Id.* P 103 (citations omitted).

[72] *Id.* PP 104–105 (citations omitted).

[73] *Id.* P 106.

[74] *Id.* P 108.

[75] *Id.* P 109.

[76] *Id.* P 110 (citations omitted).

[77] *Id.* The Commission acknowledged the important roles played by generator interconnection processes and local transmission planning processes and underscored that the Commission's findings were not intended to call into question the justness and reasonableness of either process. *Id.* P 111.

[78] *Id.* P 112.

forgoing benefits that outweigh their costs.[79]

47. The Commission determined that there is substantial evidence in the record to support the conclusion that the Commission's regional transmission planning and cost allocation requirements are deficient, thus rendering Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable. Specifically, the Commission found that existing 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.[80]

48. As to the first deficiency—the lack of sufficiently long-term planning—the Commission cited evidence in the record demonstrating that, under the status quo, most transmission planning regions do not plan beyond a 10-year transmission planning horizon.[81] The Commission stated that 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.[82] The Commission added that short-term transmission planning fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide and fails to create opportunities to ''right size'' the replacement of aging transmission facilities to address multiple transmission needs over the longer term. Further, the Commission stated that the time horizon over which much transmission planning is often occurring is shorter than the time needed to plan and construct large (*e.g.,* high voltage or long distance) transmission facilities [83] and much too short to capture all of the benefits that regional transmission facilities can provide.[84]

49. The Commission noted that 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.[85]

50. The second deficiency the Commission discussed 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; moreover, the Commission stated, transmission providers are not consistently or sufficiently doing so.[86] The Commission further stated that the record demonstrates that there are numerous factors that increasingly shape Long-Term Transmission Needs, are known and identifiable, and have reasonably predictable effects, especially in the aggregate, such as 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 regulations; and utility goals.[87] The Commission determined, however, that existing regional transmission planning processes frequently undervalue or do not consider some or all of these factors, and that the Commission's existing regional transmission planning requirements do not ensure that such factors will be sufficiently accounted for in that planning.[88] The Commission noted that 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, the Commission stated, existing regional 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, which 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.[89]

51. The third deficiency that the Commission identified is 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. The Commission pointed to evidence demonstrating that many regional transmission planning processes focus too narrowly only on some benefits, while other regional transmission planning processes fail entirely to consider cost savings associated with certain transmission facilities.[90] The Commission also explained that the cost-benefit analyses that transmission providers often use provide an inaccurate portrayal of the comparative benefits of different transmission facilities, which results in transmission customers forgoing benefits that may significantly outweigh their costs and in less efficient or cost-effective transmission investments, and ultimately contributes to Commission-jurisdictional rates that are unjust and unreasonable.[91]

52. The Commission determined that, given its findings concerning the deficiencies in existing transmission planning requirements, and its conclusion that long-term, forward-looking, and more comprehensive regional transmission planning is needed, existing cost allocation requirements are also deficient and must be modified to properly account for Long-Term Regional Transmission Planning.[92]

53. The Commission determined that its current cost allocation requirements, which were designed in the context of the Order No. 1000 regional transmission planning process, are insufficient to appropriately allocate costs associated with regional transmission facilities selected in accordance with Order No. 1920's Long-Term Regional Transmission Planning requirements.[93] 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 Order No. 1920's approach to Long-Term Regional Transmission Planning accounts for multiple drivers of Long-Term Transmission Needs and results in Long-Term Regional Transmission Facilities that produce a broader set of benefits and therefore warrants a

[79] *Id.*

[80] *Id.* P 114.

[81] *Id.* P 115.

[82] *Id.* (citations omitted).

[83] *Id.* P 116 (citations omitted).

[84] *Id.* (citations omitted).

[85] *Id.* P 117 (citations omitted).

[86] *Id.* P 118.

[87] *Id.* P 119.

[88] *Id.* P 120.

[89] *Id.* P 121 (citations omitted).

[90] *Id.* P 122 & n.312.

[91] *Id.* P 123.

[92] *Id.* P 124.

[93] *Id.* P 126.

different approach to cost allocation.[94] The Commission also explained that existing Order No. 1000 regional transmission planning processes do not mandate the consideration of specific benefits and that information concerning these benefits 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.[95] Further, the Commission noted that under existing cost allocation requirements, there is no dedicated process to engage states in the development of regional cost allocation methods. The Commission explained that engaging states in cost allocation is particularly relevant to Long-Term Regional Transmission Planning given the long lead times for construction of transmission projects, which create uncertainty for Long-Term Regional Transmission Facilities and increase the importance of ensuring that such facilities will obtain needed siting approvals from the states and are thus timely and cost-effectively developed. The Commission therefore concluded that it is both necessary and appropriate to establish specific cost allocation requirements tailored to the Long-Term Regional Transmission Planning reforms.[96]

54. The Commission found that there is substantial evidence in the record 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.[97] The Commission added that this is largely due to the deficiencies it identified regarding existing regional transmission planning and cost allocation requirements.[98] The Commission also found that, under the status quo, transmission providers are meeting many transmission needs by identifying transmission solutions and developing transmission facilities outside of the regional transmission planning and cost allocation processes or in response to near-term reliability needs.[99] The Commission stated that this approach may not identify more efficient or cost-effective transmission solutions and will saddle consumers with the costs of relatively inefficient or less cost-effective piecemeal transmission investment and expansion.[100]

55. Moreover, the Commission found that transmission needs in most transmission planning regions are rapidly changing and exacerbating 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.[101] The Commission emphasized that it 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.[102]

56. The Commission stated that Order No. 1920 does not aim to affect—either facilitate or hinder—any changes or decisions that occur outside of the Commission's jurisdiction.[103] Instead, the Commission explained, Order No. 1920 focuses on ensuring 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; Order No. 1920 seeks to ensure that such regional transmission planning processes are adequately "*accounting for*" changes occurring outside of the Commission's jurisdiction, including the resource decisions that are the exclusive jurisdiction of states.[104]

57. The Commission disagreed with arguments that it could not rely on general findings, rather than individualized analyses of each, specific transmission planning region, as the basis for Order No. 1920.[105] The Commission explained that it was acting pursuant to relevant precedent, which makes clear that the Commission need not make findings that are region-specific in every case and is instead empowered to "rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution," [106] notwithstanding regional variation among regional transmission planning processes. Moreover, the Commission acknowledged that, while transmission planning practices vary considerably between transmission planning regions, the record demonstrates that deficiencies in transmission planning processes "reach well beyond 'isolated pockets' " [107] and instead pervade large swathes of the country, including RTO/ISO and non-RTO/ISO planning regions.[108] Thus, the Commission added, Order No. 1920 does not present an "extreme 'disproportion of remedy to ailment.' " [109] The Commission also noted that it has discretion to decide the most efficient approach for resolving industry-wide problems.[110] Further, the Commission reasoned, "region-specific solutions will lead to 'siloed and disjunctive transmission planning policies [that] will not solve the problems facing the nation's electric grid.' " [111]

58. The Commission stated that the record shows that significant changes in transmission needs are well underway nationwide and that failing to account for Long-Term Transmission Needs threatens just and reasonable rates across the country.[112] The Commission also noted that significant investments in new transmission facilities are expected to occur and substantially affect Commission-jurisdictional rates that customers pay, which underscores the importance of addressing deficiencies in its regional transmission planning and cost allocation requirements now.[113]

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

59. Based on the record, the Commission found that Order No. 1920's requirements will help to ensure just and reasonable Commission-jurisdictional rates by addressing deficiencies in the existing regional transmission planning and cost allocation requirements and promoting

[94] *Id.*

[95] *Id.* (citing *ICC* v. *FERC I,* 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639).

[96] *Id.*

[97] *Id.* P 127 (citations omitted).

[98] *Id.*

[99] *Id.* (citations omitted).

[100] *Id.* P 128 (citations omitted).

[101] *Id.* P 129.

[102] *Id.* (citation omitted).

[103] *Id.* P 130 (emphasis in original).

[104] *Id.* (citing *PJM Power Providers Grp.* v. *FERC,* 88 F.4th 250, 275 (3d Cir. 2023); *Elec. Power Supply Ass'n* v. *Star,* 904 F.3d 518, 524 (7th Cir. 2018)).

[105] *Id.* P 132 (citations omitted).

[106] *Id.* (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67 (quoting *Interstate Nat. Gas Ass'n of Am.* v. *FERC,* 285 F.3d 18, 37 (D.C. Cir. 2002))).

[107] *Id.* (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67) (alteration omitted).

[108] *Id.* (citations omitted).

[109] *Id.* (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67) (alteration omitted).

[110] *Id.* (citing Order No. 1000, 136 FERC ¶ 61,051 at P 60).

[111] *Id.* (quoting ACEG NOPR Reply Comments at 17).

[112] *Id.* P 133 (citation omitted).

[113] *Id.* (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 46, 50).

enhanced reliability and more efficient or cost-effective transmission solutions.[114] The Commission noted evidence in the record demonstrating that the kind of regional transmission planning required by Order No. 1920 will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to Long-Term Transmission Needs.[115]

60. The Commission found that Long-Term Regional Transmission Planning that expands the transmission planning horizon and considers factors affecting Long-Term Transmission Needs as well as a broader list of benefits 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; [116] (3) enable opportunities to ''right size'' replacement transmission facilities; [117] (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. The Commission concluded that these regional transmission planning and cost allocation reforms will help to ensure just and reasonable rates.[118] The Commission added that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes will also enhance reliability because a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity.[119] Additionally, the Commission cited evidence demonstrating how long-term, forward-looking, and more comprehensive regional transmission planning can better identify reliability needs and resolve those needs with more efficient or cost-effective transmission solutions.[120]

[114] *Id.* P 134.

[115] *Id.* P 135.

[116] *Id.* P 136 (citation omitted).

[117] *Id.* (citations omitted).

[118] *Id.* (citations omitted).

[119] *Id.* P 137.

[120] *Id.* P 138 (citations omitted).

B. The Commission Adequately Demonstrated That Existing Rates, or Practices Affecting Rates, Are Unjust and Unreasonable

61. We sustain the Commission's determination in Order No. 1920 that existing regional transmission planning and cost allocation processes are unjust and unreasonable, and unduly discriminatory or preferential. We conclude that this finding, as well as the Commission's finding that the identified deficiencies in transmission planning and cost allocation processes render existing Commission-jurisdictional rates unjust and unreasonable, was based on substantial record evidence, reflecting significant input from nearly 200 stakeholders across the country, third-party reports and studies, and the Commission's extensive knowledge of the industry and expert predictions regarding the transmission planning processes and cost allocation requirements that the Commission itself has established and oversees in carrying out its statutory responsibilities. We disagree with several rehearing parties who argue that the Commission failed to satisfy its burden under the first prong of FPA section 206 to show that Order No. 1000 regional transmission planning and cost allocation processes are unjust, unreasonable, or unduly discriminatory and preferential.[121] First, we disagree with certain rehearing parties as to the nature of the Commission's evidentiary burden under FPA section 206. Second, we conclude that the Commission's factual findings and the substantial evidence supporting those findings satisfies, and exceeds, the Commission's burden under FPA section 206. Third, we find that the ''deficiencies identified by the Commission'' in Order No. 1920 do not '''exist[ ] only in isolated pockets' '' and such evidence is supported by the record. Finally, we conclude that the Commission has authority to conduct a nationwide rulemaking. We address these points in turn.

1. The Commission Correctly Characterized Its Statutory Burden

a. Requests for Rehearing

62. SERTP Sponsors contend that the Commission must demonstrate more than theoretical deficiencies to support nationwide policies and that systemic problems must be demonstrated beyond isolated issues.[122] SERTP Sponsors argue that Order No. 1920's findings, which are based on theory and supposition, are insufficient to carry the applicable burden and are contradicted by substantial specific evidence about SERTP.[123] SERTP Sponsors argue that *South Carolina Public Service Authority* v. *FERC* ''does not stand for the proposition that any assertion of any theoretical problem by FERC is enough to satisfy the first step of the analysis under [s]ection 206.'' [124] SERTP Sponsors contend that except in limited circumstances—*e.g.,* when there is a lack of empirical evidence—the D.C. Circuit requires more than theoretical deficiencies to support nationwide policies.[125]

63. Relatedly, Industrial Customers claim that Order No. 1920 is ''legally infirm'' because it does not make specific findings that rates and practices are unjust, unreasonable, or unduly discriminatory or preferential and instead ''proposes to amend Order No. 1000 based upon mere concerns that Order No. 1000 *may not* be planning transmission in a manner that comports with the FPA.'' [126]

b. Commission Determination

64. We sustain our determination under the first prong of FPA section 206 and find that the Commission relied on sufficient and appropriate evidence to support its determination that existing rates are unjust and unreasonable. We disagree with SERTP Sponsors' and Industrial Customers' arguments that the Commission did not satisfy its section 206 burden because its analysis under the first prong of FPA section 206 was predicated ''entirely on theory and supposition'' [127] or on ''mere concerns'' that Order No. 1000 processes ''*may not* be planning transmission in a manner that comports with the FPA.'' [128] Setting aside that in making this determination the Commission did not rely solely on ''supposition'' or ''mere concerns'' about deficiencies in the Order No. 1000 regional transmission planning and cost allocation processes,[129] SERTP

[121] Alabama Commission Rehearing Request at 3–4; Designated Retail Regulators Rehearing Request at 3, 7–8, 19–22; Industrial Customers Rehearing Request at 3–4, 6, 11–18; SERTP Sponsors Rehearing Request at 28–29, 31–37; Undersigned States Rehearing Request at 7, 19–21; Arizona Commission Rehearing Request at 19–20.

[122] SERTP Sponsors Rehearing Request at 34 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 71).

[123] *Id.*

[124] *Id.* at 31 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 65).

[125] *Id.* at 29, 31, 34.

[126] Industrial Customers Rehearing Request at 16–17 (emphasis in original).

[127] SERTP Sponsors Rehearing Request at 31.

[128] Industrial Customers Rehearing Request at 16–17.

[129] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at PP 93–97, 114–123 (discussed below in The Commission Adequately Supported Its Determination on Step One of Section 206 section).

Sponsors' and Industrial Customers' arguments disregard well-established principles regarding the findings and type of evidence sufficient to support a conclusion that the Commission's burden under the first prong of FPA section 206 has been satisfied, as established by longstanding authority, including the D.C. Circuit's opinion in *South Carolina Public Service Authority* v. *FERC.*

65. In *South Carolina Public Service Authority* v. *FERC,* the D.C. Circuit—reviewing Order No. 1000, which the Commission adopted to address the ''theoretical threat'' of unjust or unreasonable rates ''stemm[ing] from the absence of [transmission] planning processes that take a sufficiently broad view of both the tasks involved and the means of addressing them''—rejected arguments similar to those made here by Industrial Customers.[130] In particular, petitioners there, similar to Industrial Customers here, argued that the '''theoretical threat' described by the Commission fail[ed] to satisfy its evidentiary burden under [s]ection 206 . . . .'' [131]

66. The court squarely rejected that contention.[132] It explained that the substantial evidence required to support a finding that an existing practice affecting rates is ''unjust, unreasonable, unduly discriminatory or preferential'' pursuant to FPA section 206 ''requires 'more than a scintilla' but 'less than a preponderance' of evidence.'' [133] Substantial evidence, however, ''does not necessarily mean empirical evidence,'' [134] and, in satisfying the substantial evidence standard, the Commission may rely on its own predictions as long as they are '''at least likely enough to be within the Commission's authority' and [are] based on reasonable economic propositions.'' [135] As the court recognized, ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [136]

67. The court in reviewing Order No. 1000 determined that the Commission had satisfied its evidentiary burden under section 206. In particular, the Commission had identified ''significant changes in the nation's electric power industry'' that presented ''significant challenges to the development and cost allocation of interstate transmission projects'' and highlighted five deficiencies in Order No. 890's transmission planning and cost allocation processes.[137] Ultimately, the court held that the Commission's determination that the then-current transmission planning and cost allocation practices were unjust or unreasonable was based on substantial evidence.[138]

68. By insisting that the Commission was required to demonstrate that rates or practices are, *in fact,* unjust, unreasonable, or unduly discriminatory or preferential,[139] SERTP Sponsors and Industrial Customers overlook principles articulated in *South Carolina Public Service Authority* v. *FERC,* including that the Commission need not provide empirical evidence for every proposition and may instead rely upon the threat of unjust and unreasonable rates as a basis for taking action.[140] Their argument is predicated on a faulty premise that, in a rulemaking setting, the Commission must wait for a threat to result in actual harm, and may not act where it anticipates harmful consequences.[141] But in *South Carolina Public Service Authority* v. *FERC,* the court explicitly reached the opposite conclusion, holding that the Commission satisfied its evidentiary burden under section 206 by relying on the theoretical threat to just and reasonable rates even though the Commission acknowledged other evidence in the record.[142] SERTP Sponsors are thus incorrect to suggest that the *South Carolina Public Service Authority* v. *FERC* court allowed the Commission to rely on generic factual findings only because the record lacked empirical evidence.[143]

69. *South Carolina Public Service Authority* v. *FERC* makes clear that, because ''substantial evidence'' is not limited to empirical evidence and may include generic factual predictions, the Commission could have satisfied its evidentiary burden under the first prong of FPA section 206 with analysis based on theoretical threats and predictions regarding such threats based on reasonable economic propositions within the Commission's expertise.[144] Here, however, the Commission established a theoretical threat and, as discussed below, also cited substantial empirical and other record evidence to support its finding that the existing regional transmission planning processes and cost allocation requirements—and the rates that have resulted from them—are unjust and unreasonable.

2. The Commission Adequately Supported Its Determination on Step One of Section 206

a. Requests for Rehearing

70. Designated Retail Regulators argue that, in its analysis under the first prong of section 206 of the FPA, the Commission made conclusory, ''blanket claims that are unsupported by evidence.'' [145] Undersigned States similarly assert that the Commission does not ''point to evidence in the record sufficient to support'' a finding that existing regional transmission planning and cost allocation processes are resulting in unjust, unreasonable, unduly discriminatory, and preferential Commission-jurisdictional rates because ''such evidence does not exist.'' [146] Arizona Commission contends that the evidence in the record used to support Order No. 1920's section 206 finding

[130] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64 (alteration omitted) (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 52).

[131] *Id.*

[132] *Id.*

[133] *Id.* at 54 (quoting *Fla. Gas Transmission Co.* v. *FERC,* 604 F.3d 636, 645 (D.C. Cir. 2010)), 64–65 (citing 16 U.S.C. 824e(a)), 5 U.S.C. 706(2)(E))).

[134] *Id.* at 65 (citing 5 U.S.C. 706(2)(E)); *see also Xcel Energy Servs. Inc.* v. *FERC,* 41 F.4th 548, 560–61 (D.C. Cir. 2022) (''In making decisions, it is 'perfectly legitimate for the Commission to base its findings on basic economic theory,' including relying on 'generic factual predictions,' as long as the agency 'explains and applies the relevant economic principles in a reasonable manner.''' (cleaned up) (quoting *Sacramento Mun. Util. Dist.* v. *FERC,* 616 F.3d 520, 531 (D.C. Cir. 2010) (per curiam))); *id.* (''Where the 'promulgation of generic rate criteria clearly involves the determination of policy goals or objectives, and the selection of means to achieve them,' the 'courts reviewing an agency's selection of means are not entitled to insist on empirical data for every proposition on which the selection depends.''' (alterations omitted) (quoting *Associated Gas Distribs.* v. *FERC,* 824 F.2d 981, 1008 (D.C. Cir. 1987) (*Associated Gas Distributors*))).

[135] *Id.; see also id.* at 76 (''[A]t least in circumstances where it would be difficult or even impossible to marshal empirical evidence, the Commission is free to act based upon reasonable predictions rooted in basic economic principles.'').

[136] *Id.* at 65 (quoting *Associated Gas Distributors,* 824 F.2d at 1008); *see also Cent. Hudson Gas & Elec. Corp.* v. *FERC,* 783 F.3d 92, 109 (2d Cir. 2015) (''FERC may permissibly rely on economic theory alone to support its conclusions so long as it has applied the relevant economic principles in a reasonable manner and adequately explained its reasoning.'').

[137] *Id.* at 66.

[138] *See id.*at 67.

[139] Industrial Customers Rehearing Request at 16–17; SERTP Sponsors Rehearing Request at 34.

[140] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64–65; *see also id.* at 85 (''[W]hether a threat of unjust or unreasonable rates derives from a practice or the absence thereof, Section 206 empowers the Commission to address it.''); *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006) (stating that the Commission could choose to ''rely solely on a theoretical threat'').

[141] *See* Industrial Customers Rehearing Request at 16–17.

[142] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64, 67.

[143] SERTP Sponsors Rehearing Request at 29.

[144] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 65 (quoting *Associated Gas Distributors,* 824 F.2d at 1008).

[145] Designated Retail Regulators Rehearing Request at 20–21.

[146] Undersigned States Rehearing Request at 21.

consists largely of comments from special interest groups that will profit from Order No. 1920 and not evidence specific to the Arizona Commission.[147]

71. Industrial Customers claim that, rather than making specific findings that existing practices are unjust and unreasonable, the Commission made ''several generic assertions . . . to reach very broad conclusions,'' [148] and ''generically assert[ed]'' that the Commission satisfies its burden under the first prong of the FPA section 206 inquiry ''based on the record.'' [149] Industrial Customers assert that the failure to reach specific findings, supported by substantial evidence, under the first prong of FPA section 206 renders Order No. 1920 legally infirm.[150] Industrial Customers claim that the absence of detailed and substantiated findings makes it ''difficult, if not impossible'' for transmission providers to file compliance filings because it will be challenging to develop and propose solutions without an understanding of the root problem the Commission is trying to fix.[151]

b. Commission Determination

72. We continue to find that the Commission made adequate findings under the first prong of FPA section 206 and marshalled substantial evidence to support those findings. We are therefore not persuaded by rehearing parties' arguments to the contrary. Below, we first summarize the empirical and other record evidence the Commission cited to support its findings that Commission-jurisdictional regional transmission planning and cost allocation processes are 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.[152] Next, we summarize the Commission's generic factual predictions. We conclude that this evidence is more than sufficient to meet the Commission's evidentiary burden under section 206.

73. Based on the robust record before it, the Commission concluded that transmission investment, which has increased nationwide since the Commission issued Order No. 1000,[153] is likely to grow substantially in coming years due to three factors that are driving a growing need for new transmission infrastructure.[154] First, reports and comments in the record demonstrated that longer-term reliability needs are changing as transmission providers increasingly rely on regional transmission facilities to ensure operational stability as extreme weather events become more frequent and variable resources increasingly enter the resource mix.[155] Based on evidence in the record, the Commission concluded that 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.[156] Second, the Commission noted evidence that electric demand is projected to increase significantly in the coming decades due to electrification trends and new large loads associated with evolving industrial and commercial needs.[157] Again, relying on record evidence, the Commission found that these increases in aggregate electricity demand will have significant consequences for the transmission system.[158] Third, the Commission found that the resource mix is changing due to federal, federally-recognized Tribal, state, and local policies,[159] customer demands for clean energy,[160] utility

[147] Arizona Commission Rehearing Request at 19.

[148] Industrial Customers Rehearing Request at 16.

[149] *Id.* at 13 (alteration omitted).

[150] *Id.* at 17.

[151] *Id.* at 17–18.

[152] Order No. 1920, 187 FERC ¶ 61,068 at PP 114–122.

[153] *Id.* P 92 (referencing a study by the US DOE, which found that annual investment in transmission first exceeded $5 billion per year in 2006, doubled to more than $10 billion per year by 2010, doubled again by 2016, and has been between $18 billion and $22 billion annually since 2014 (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*)); *id.* (citing estimates from The Brattle Group and Grid Strategies that transmission developers in the United States invested $20 to $25 billion annually in transmission facilities from 2013 to 2020 (citing Brattle-Grid Strategies Oct. 2021 Report at 2); Brattle Apr. 2019 Competition Report at 2–3 & fig.1)).

[154] *Id.* P 93 (citing a number of studies projecting sustained transmission spending through at least 2050, including one by Princeton University projecting 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, as well as another by The Brattle Group projecting $750 billion of new transmission investment between 2023 and 2050. (citing Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts,* at 108 (Oct. 2021), *https://netzeroamerica.princeton.edu/the-report;* 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*)).

[155] The Commission cited comments and reports demonstrating that transmission infrastructure can be critical to system reliability during extreme weather events such as Winter Storm Uri. *Id.* P 94 & n.209 (citing ACEG NOPR Initial Comments at 22 n.63 (stating that 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.''); 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.'')). The Commission also cited research from US DOE's Lawrence Berkeley National Laboratory 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, further evidence of the significant value of transmission during unanticipated events. *Id.*P 94 (citing LBNL Aug. 2022 Transmission Value Study at 33).

[156] *Id.* P 94 (citing LBNL Aug. 2022 Transmission Value Study at 33; Clean Energy Associations NOPR Initial Comments at 5).

[157] *Id.* P 95 (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*); 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.'')).

[158] *See id.* P 95 (citing National Grid NOPR 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*))).

[159] *Id.* P 96 & nn.223–227 (noting numerous jurisdictions that have adopted decarbonization, electrification, and renewable energy-related laws and policies); *id.* (citing ACORE NOPR Initial Comments at 1–2 & n.2; 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* (''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.''); Evergreen Action NOPR Initial Comments at 3–4; NextEra NOPR Reply Comments at 5); *id.* P 99.

[160] *Id.* P 97 (''Since 2014, for example, 'commercial and industrial customers have contracted for more than 52 GW of clean energy.'''

emission commitments,[161] and the changing economics of resources that comprise the resource mix.[162]

74. Considering the changing transmission investment landscape, the Commission then relied on substantial record evidence to find that the Commission's existing regional transmission planning and cost allocation requirements are deficient in three ways and therefore fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis.[163]

75. The first deficiency that the Commission identified is the lack of a sufficiently long-term assessment of transmission needs.[164] The Commission explained that most transmission planning regions do not plan beyond a 10-year transmission planning horizon,[165] which is shorter than the time needed to plan and construct large (*e.g.,* high voltage or long distance) transmission facilities[166] or to capture all of the benefits that regional transmission facilities can provide.[167] According to comments and studies in the record, short-term transmission planning also fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide and does not create opportunities to ''right size'' the replacement of aging transmission facilities.[168] Based on this evidence, the Commission concluded that 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.[169]

76. The second deficiency that the Commission identified is that transmission providers are not required to account adequately on a forward-looking basis for known determinants of Long-Term Transmission Needs or to account 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.[170] The Commission highlighted concrete evidence of this deficiency, including that some regional transmission planning processes ignore factors relevant to identifying transmission needs,[171] while others fail to account for factors that will shape future load.[172] The Commission added that, while forecasting necessarily involves uncertainty, the record demonstrates that there are numerous factors that increasingly shape Long-Term Transmission Needs, that are known and identifiable, and have reasonably predictable effects, especially in the aggregate.[173] These include, for example, reliability needs driven by the impact of extreme weather,[174] trends in future generation additions and retirements,[175] load growth,[176] federal, federally-recognized Tribal, state, and local laws and

(alteration omitted) (quoting Advanced Energy Buyers NOPR Initial Comments at 5)).

[161] *Id.* P 97 & nn.233–37 (noting that Exelon, Dominion, AEP, Southern, Entergy, Duke Energy, NextEra, and Tennessee Valley Authority have all announced some version of a net-zero carbon emission plan or commitment).

[162] *Id.* P 97 & n.239 (citing ACORE ANOPR NOPR Initial Comments at app. 1, p. 22 (''Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.'')); Order No. 1920, 187 FERC ¶ 61,068 at P 99 (''[A]s of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources[,] . . . [and] 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.'' (citing SREA NOPR Initial Comments at 1–2; AEE NOPR Initial Comments at 12–13; California Commission NOPR Initial Comments at 65; Renewable Northwest NOPR Initial Comments at 36; FERC, State of the Markets 2020, at 10, 12 (Mar. 2021); FERC, State of the Markets 2023, at 4 (Mar. 2024); US DOE Initial Comments at app. B, PP. 8–9, 26).

[163] *Id.* P 112.

[164] Order No. 1920, 187 FERC ¶ 61,068 at P 115 (citing 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 NOPR 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'')).

[165] *Id.* (noting that commenters point out that ISO–NE, SERTP, and NorthernGrid use a 10-year transmission planning horizon, while PJM uses 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).

[166] *Id.* P 116 (citing AEP NOPR Initial Comments at 11; Nevada Commission NOPR Initial Comments at 7 n.24; PIOs NOPR Initial Comments at 14; Renewable Northwest NOPR Initial Comments at 5; SEIA NOPR Initial Comments at 6). The Commission discussed MISO's MVP initiative, which took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, a 10-year period that does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval. Order No. 1920, 187 FERC ¶ 61,068 at P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio,* at 39 (2021)).

[167] *Id.* (citing SEIA NOPR Initial Comments at 6; US DOE NOPR Initial Comments at 33).

[168] *Id.* (citing ACORE NOPR 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).

[169] *Id.* P 117 & n.290 (''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.'' (quoting US DOE ANOPR Initial Comments at 10)); *id.* (''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.'' (quoting 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*)).

[170] *Id.* P 118.

[171] *Id.* (discussing record evidence that some existing regional transmission planning processes ignore trends in future generation, the impact of extreme weather, state laws, and utility goals) (citing Acadia Center and CLF NOPR Initial Comments at 1; GridLab NOPR Initial Comments at 4–5; Brattle-Grid Strategies Oct. 2021 Report at 36; Grid Strategies July 2021 Extreme Weather Report at 5; SPP Market Monitor ANOPR Initial Comments at 3 & n.5; Renewable Northwest NOPR Initial Comments at 4, 8, 12; SREA NOPR Initial Comments at 25)).

[172] *Id.* (discussing record evidence that existing regional transmission planning processes fail to account for factors shaping electrification trends like electric vehicles and data centers (citing AEE ANOPR Initial Comments at 18; Clean Energy Buyers NOPR Initial Comments at 7–8; National Grid NOPR Initial Comments at 8; AEE ANOPR Initial Comments at 18; Rocky Mountain Institute NOPR Supplemental Comments at 1; WIRES NOPR Supplemental Comments at attach. 1, p. 36)).

[173] *Id.* P 119.

[174] *Id.* P 120 (citing ACEG NOPR Initial Comments at 63; NERC NOPR Initial Comments at 6; Evergreen Action NOPR 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 NOPR Initial Comments at 2).

[175] *Id.* P 120 (citing Pattern Energy NOPR Initial Comments at 26; SEIA NOPR Initial Comments at 9).

[176] *Id.* (citing Northwest and Intermountain NOPR Initial Comments at 5 n.12; 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'')).

regulations,[177] and utility goals.[178] The Commission explained, however, that existing regional transmission planning processes frequently undervalue or do not consider some or all of these factors, and the Commission's existing regional transmission planning requirements do not ensure otherwise.[179] The Commission found that the failure to adequately consider such factors delays planning for the transmission system's changing operational needs until shortly before those transmission needs manifest, resulting in transmission planning processes that 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.[180]

77. The Commission explained that the third deficiency is that transmission providers are not required to adequately consider the broader set of benefits that accrue to regional transmission facilities planned to meet Long-Term Transmission Needs.[181] Relying on record evidence, the Commission found that many current regional transmission planning and cost allocation processes consider only a narrow subset of benefits that regional transmission facilities provide[182] or fail entirely to consider cost savings associated with certain transmission facilities.[183]

78. These deficiencies have concrete consequences that illustrate the deleterious effects of inadequate regional transmission planning processes. For instance, the Commission cited evidence showing that investment in regional transmission facilities has declined in some regions as compared to the investment that was occurring prior to Order No. 1000 and that, across all non-RTO/ISO regions, not a single transmission facility has been selected since implementation of Order No. 1000.[184] Further, the Commission noted that within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process occur, much of that investment has been in transmission projects that only address immediate reliability needs.[185]

79. At the same time, the Commission found, significant expansion of the transmission system is occurring through one-off, piecemeal, interconnection-related network upgrades constructed in response to individual generator interconnection requests.[186] The Commission noted the shortcomings of relying on the generator interconnection process for addressing transmission needs, including that 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.[187]

80. The Commission also cited evidence that, since the issuance of Order No. 1000, the majority of investment in transmission facilities has been in local transmission facilities, a trend that is accelerating across multiple regions.[188] The Commission pointed out 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.[189]

81. Relying on the foregoing record of empirical and other record evidence, the Commission found that existing regional transmission planning requirements are deficient and fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking, and comprehensive basis.[190] Substantial facts in the record also supported the Commission's finding 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,[191] a trend that

[177] *Id.* PP 119, 120 (citing Acadia Center and CLF NOPR Initial Comments at 8; AEE NOPR 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.'')).

[178] *Id.* P 120 (citing Renewable Northwest NOPR Initial Comments at 6; SREA NOPR Initial Comments at 41–46).

[179] *Id.*

[180] *Id.* P 121 (PIOs NOPR Initial Comments at 10–11; Renewable Northwest NOPR Initial Comments at 8).

[181] *Id.* P 122 (citation omitted).

[182] *Id.* (citing Brattle-Grid Strategies Oct. 2021 Report at 2 (''[M]ost 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.''); Massachusetts Attorney General ANOPR Initial Comments at 22; PIOs NOPR Initial Comments at 10–11).

[183] *Id.* (citing SREA NOPR 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.'')).

[184] *Id.* P 101 (citing 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 25 & fi. 8 (Jan. 2021), *https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf;* 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.'') (citation omitted); State Agencies NOPR Initial Comments at 23 (''Regionally planned projects have [ ] declined in RTOs/ISOs . . . .'' (citing John C. Gravan & 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*); FERC, Staff Report, *2017 Transmission Metrics,* at 19 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf*).

[185] *Id.* P 101 (citing Southwestern Power Group NOPR Initial Comments at 15; PIOs ANOPR Initial Comments at 93 & n.276; Ari Peskoe, *Is the Utility Syndicate Forever?,* 42 Energy L.J. 1, 56–57 (2021)).

[186] *Id.* P 104 (citing Pine Gate NOPR Initial Comments at 6, 8–10; PIOs NOPR Initial Comments at 9).

[187] *Id.* P 106 (citing Anbaric NOPR Initial Comments at 5; Clean Energy Associations NOPR Initial Comments at 15; Exelon NOPR Initial Comments at 5; Pine Gate NOPR Initial Comments at 9; PIOs NOPR Initial Comments at 10; SEIA NOPR Initial Comments at 2; Southeast PIOs NOPR Initial Comments at 37).

[188] *Id.* P 109 (citing NOPR, 179 FERC ¶ 61,028 at PP 39–40 (2022)).

[189] *Id.* (citing PIOs NOPR Initial Comments at 9).

[190] *Id.* P 127 (citing New Jersey Commission NOPR 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 NOPR 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'')).

[191] *Id.* PP 127–128 (citing LS Power NOPR Initial Comments at 46–50; PIOs NOPR 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)).

reflects that existing regional transmission planning requirements are leading to relatively inefficient or less cost-effective results.

82. Moreover, as courts have made clear, the Commission was also entitled to base its findings regarding the need for reform on generic factual predictions.[192] In *Associated Gas Distributors,* the court explained that the Commission is permitted to act on predictions that are unsupported by record evidence when such predictions are ''at least likely enough to be within the Commission's authority'' and based on reasonable behavioral or economic assumptions.[193] Indeed, ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [194] Thus, in *South Carolina Public Service Authority* v. *FERC,* the court held that the Commission satisfied its burden on the first prong of FPA section 206 analysis where ''[t]he threat to just and reasonable rates arose, *in the Commission's judgment,* from existing planning and cost allocation practices that could thwart the identification of more efficient and cost-effective transmission solutions.'' [195]

83. Here, relying on its expertise and knowledge of the industry, the Commission made several predictions that were fully consistent with the grounds for action that courts have accepted in the past, including in *Associated Gas Distributors* and *South Carolina Public Service Authority* v. *FERC.* First, the Commission made such predictions when it explained how observed deficiencies in existing regional transmission planning and cost allocation requirements are resulting in deleterious consequences and ultimately rendering rates unjust and unreasonable.[196] Next, the Commission predicted that existing cost allocation requirements—which were designed and established in the context of existing shorter-term Order No. 1000 regional transmission planning processes and lack a dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods—are insufficient to appropriately allocate costs associated in the context of the Long-Term Regional Transmission Planning requirements established in Order No. 1920.[197] Finally, the Commission anticipated that, absent Order No. 1920's reforms, 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.[198] Such predictions are precisely the type of evidence that courts have permitted the Commission to use as the basis for section 206 rulemaking.

84. Given both the empirical and other record evidence and the generic factual predictions on which the Commission relied, we are unpersuaded by Designated Retail Regulators' and Undersigned States' arguments [199] that the Commission's determination under the first prong of FPA section 206 was unsupported by substantial evidence. Indeed, the Commission's findings regarding ongoing changes to the nation's electric power industry and deficiencies in existing transmission planning and cost allocation processes, along with the evidence supporting those findings, are similar to, or the same as, the type of findings and evidence that formed the basis for action in Order No. 1000 and that the *South Carolina Public Service Authority* v. *FERC* court determined satisfied the Commission's burden under the first prong of FPA section 206.[200]

85. For these same reasons, we disagree with Arizona Commission's unsubstantiated contention that the evidence in the record on which the Commission relied to satisfy its section 206 burden consists largely of comments from special interest groups that will profit from the final rule.[201] The Commission's findings were based on an extensive record consisting of over 30,000 pages of comments from nearly 200 stakeholders, including industry participants such as transmission providers,[202] generation developers,[203] trade associations,[204] customer groups,[205] and governmental entities.[206] The Commission's findings also relied upon many reports and studies in the record and the Commission's expert predictions.[207] Arizona Commission disregards this substantial evidence.

86. We are also unpersuaded by Industrial Customers' assertion that the absence of substantial evidence makes it ''difficult if not impossible'' for transmission providers to submit compliance filings because it will be challenging to develop and propose solutions without an understanding of

[192] *See Citadel FNGE Ltd.* v. *FERC,* 77 F.4th 842, 858 (D.C. Cir. 2023); *Xcel Energy Servs. Inc.* v. *FERC,* 41 F.4th at 560–61; *Associated Gas Distributors,* 824 F.2d at 1008.

[193] *Associated Gas Distributors,* 824 F.2d at 1008 (discussing *Wis. Gas Co.* v. *FERC,* 770 F.2d 1144 (D.C. Cir. 1985); *Elec. Consumers Res. Council* v. *FERC,* 747 F.2d 1511 (D.C. Cir. 1984)).

[194] *Associated Gas Distributors,* 824 F.2d at 1008.

[195] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 66 (emphasis added).

[196] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 117, 121, 123.

[197] *Id.* P 126.

[198] *Id.* P 113.

[199] Designated Retail Regulators Rehearing Request at 20–21; Undersigned States Rehearing Request at 21.

[200] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 65–67; *see also* Order No. 1000, 136 FERC ¶ 61,051 at PP 44–47, 78–83.

[201] *See* Arizona Commission Rehearing Request at 19.

[202] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at P 115 (citing PJM NOPR Initial Comments; MISO ANOPR Reply Comments; ITC NOPR Initial Comments); *id.* P 116 (citing AEP NOPR Initial Comments); *id.* P 118 (citing National Grid NOPR Initial Comments); *id.* P 136 (citing Exelon NOPR Initial Comments.

[203] *See, e.g., id.* P 120 (citing Pattern Energy NOPR Initial Comments); *id.* P 127 (citing NextEra ANOPR Initial Comments; LS Power NOPR Initial Comments).

[204] *See, e.g., id.* P 116 (citing SEIA ANOPR Initial Comments); *id.* P 137 (citing EEI NOPR Initial Comments).

[205] *See, e.g., id.* P 118 (citing Clean Energy Buyers NOPR Initial Comments; ELCON NOPR Initial Comments); *id.* PP 119–120 (citing Industrial Customers NOPR Initial Comments).

[206] *See, e.g., id.* P 115 (citing Massachusetts Attorney General NOPR Initial Comments; US DOE ANOPR Initial Comments); *id.* P 116 (citing Nevada Commission NOPR Initial Comments); *id.* P 120 (citing NERC NOPR Initial Comments); *id.* PP 121, 127, 135 (citing New Jersey Commission NOPR Initial Comments); *id.* P 128 (citing Michigan State Entities NOPR Initial Comments).

[207] *See, e.g., id.* P 92 (citing US DOE, *National Electric Transmission Congestion Study,* (Sept. 2020), *https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf*); Brattle-Grid Strategies Oct. 2021 Report); *id.* P 101 (citing ACEG Jan. 2021 Planning Report; John C. Gravan & Rob Gramlich, NRRI Insights, A New State-Federal Cooperation Agenda for Regional and Interregional Transmission (Sept. 2021), *https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685*); FERC, Staff Report, *2017 Transmission Metrics* (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf*)); *id.* P 102 (citing Midcontinent Indep. Sys. Operator, *RGOS: Regional Generation Outlet Study* (Nov. 2020)); MTEP2017 Review); *id.* P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio* (2021); Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report* (July 28, 2022), *https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf*); *id.* P 118 (citing Grid Strategies July 2021 Extreme Weather Report; Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms* (July 2022), *https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf;* Rob Gramlich, et al., *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)); *id.* P 120 (citing BPA, *TSR Study and Expansion Process* (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 (Dec. 2023), *https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf*).

the root problem that the Commission is trying to fix.[208] As discussed above, the Commission made detailed findings addressing the deficiencies of existing transmission planning and cost allocation requirements and the processes related to those requirements.[209] Moreover, in developing their compliance filings, transmission providers will rely on the Commission's specific identification of the new requirements established under the second prong of FPA section 206, not on the deficiencies in existing transmission planning and cost allocation processes and requirements identified under the first prong of the Commission's section 206 analysis. We are therefore not persuaded that Order No. 1920's findings lack the requisite specificity to enable transmission providers to make compliance filings.

3. The Commission Identified Deficiencies That Exist Beyond Isolated Pockets

a. Requests for Rehearing

87. Alabama Commission and SERTP Sponsors assert that Order No. 1920's generalized observations criticizing the effectiveness of existing transmission planning processes are based on examples from other parts of the country and do not apply to, or address evidence regarding, Alabama and the Southeast.[210] According to Alabama Commission, Alabama and SERTP already achieve many, if not most, of the goals of the final rule.[211] Alabama Commission contends that Alabama has a resource planning process that accounts for needed transmission buildout to maintain reliable service and proactively plans its transmission system to maintain deliveries from existing resources and accommodate generation additions.[212] Alabama Commission adds that the SERTP process ensures that there are no regional transmission solutions that are more efficient and cost-effective than the solutions identified through the underlying state-jurisdictional process.[213]

88. SERTP Sponsors allege that the SERTP process has been highly efficient, and that its integrated resource plan and request for proposal-driven transmission planning and other similar processes effectively address the Commission's concerns regarding siloed planning, lack of scenario planning, and local versus regional project focus. SERTP Sponsors argue that, while the court in *South Carolina Public Service Authority* v. *FERC* allowed the Commission to support a rulemaking by finding a systemic problem not limited to isolated pockets, given SERTP's scale, scope, and that it does not suffer from the theoretical deficiencies identified in Order No. 1920, the Commission has not satisfied the standard set out in *South Carolina Public Service Authority* v. *FERC.*[214] SERTP Sponsors claim that they ensure a comprehensive and proactive approach to transmission system development by incorporating various factors into their planning, including reliability, economic growth, environmental attributes, and public policy requirements.[215] According to SERTP Sponsors, the alternative projects identified through its regional transmission planning analyses have not proved to be more efficient or cost-effective than those identified through SERTP's integrated resource plan and request for proposal-driven transmission planning.[216]

89. SERTP Sponsors also disagree with Order No. 1920's finding that nationwide transmission grid expansion is primarily driven through the generator interconnection process, because in the Southeast, transmission expansion is driven by the underlying integrated resource plan/request for proposal and other similar planning processes.[217] SERTP Sponsors state that Southern Companies added $5.3 billion in transmission capital expenditures from 2017–2021, with only $57 million (just over 1%) related to generation interconnection.[218] Similarly, SERTP Sponsors explain that Duke Energy added an estimated $503 million of transmission facilities to its transmission plan, targeted at unlocking areas of its transmission system that were repeatedly identified in past generator interconnection studies as constrained to more timely and cost-effectively integrate needed generation resources.[219] SERTP Sponsors contend that Order No. 1920 ignored this evidence.[220]

90. Designated Retail Regulators and Undersigned States aver that, contrary to the Commission's claims, the evidence in the record demonstrates that a substantial portion of transmission providers have been and are engaging in long-term planning.[221] For example, Designated Retail Regulators and Undersigned States point to MISO's Multi-Value Projects (MVP) process, which they claim includes most of the requirements of Order No. 1920.[222] Designated Retail Regulators and Undersigned States also contend that CAISO, NYISO, Southern Companies, and other transmission planners also have sufficient long-term planning and that SPP indicated in its NOPR comments that its OATT requires planning processes that are sufficient to meet the intent and desired outcomes of Order No. 1920.[223]

b. Commission Determination

91. We disagree with rehearing parties who argue that the Commission did not satisfy its burden under the first prong of FPA section 206 because certain transmission providers may already engage in some form of long-term transmission planning.[224] We are satisfied that the Commission identified deficiencies in existing regional transmission planning and cost allocation processes that exist beyond isolated pockets.

92. First, ''[t]hat some commenters may engage in sufficient transmission planning processes 'is as unastonishing as it is irrelevant,' '' where, as here, the deficiencies identified by the Commission and supported by substantial evidence reach well beyond ''isolated pockets.'' [225] Record evidence demonstrates that transmission planning regions across the country—including ISO–NE, SERTP, and NorthernGrid—do not plan beyond a 10-

[208] Industrial Customers Rehearing Request at 17.

[209] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[210] Alabama Commission Rehearing Request at 3; SERTP Sponsors Rehearing Request at 28–29, 31.

[211] Alabama Commission Rehearing Request at 3.

[212] *Id.* at 3–4.

[213] *Id.* at 4.

[214] SERTP Sponsors Rehearing Request at 34 n.100.

[215] *Id.* at 32.

[216] *Id.* at 33.

[217] *Id.* at 36.

[218] *Id.* at 36–37.

[219] *Id.* at 37 (citing Duke NOPR Initial Comments at 8–9).

[220] *Id.* (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 43 (1983) (*State Farm*) (internal citation omitted)).

[221] Designated Retail Regulators Rehearing Request at 21–22; Undersigned States Rehearing Request at 22–23.

[222] Designated Retail Regulators Rehearing Request at 21–22; Undersigned States Rehearing Request at 22.

[223] Designated Retail Regulators Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65–66); SPP NOPR Initial Comments at 3); Undersigned States Rehearing Request at 22–23 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65–66); SPP NOPR Initial Comments at 3).

[224] Alabama Commission at 3–4; Designated Retail Regulators Rehearing Request at 21–22; Undersigned States Rehearing Request at 22–23; SERTP Sponsors Rehearing Request at 28–37.

[225] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67 (first quoting *Wis. Gas Co.* v. *FERC,* 770 F.2d at 1157; and then quoting *Associated Gas Distributors,* 824 F.2d at 1019).

year transmission planning horizon,[226] which is problematic for several reasons, including that regional transmission facilities often have lead times that exceed 10 years [227] and that a 10-year transmission planning horizon is much too short to capture all of the benefits that regional transmission facilities can provide.[228] Further, comments and reports in the record establish that transmission planning processes in several regions do not account for known determinants of Long-Term Transmission Needs such as trends in future generation [229] and extreme weather.[230] The record demonstrates that many regional transmission planning processes also fail to adequately consider the range of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[231] And the Commission cited evidence showing that, except in limited cases, transmission providers in many regions do not conduct multi-driver or portfolio transmission planning, which has led to ratepayers paying for relatively inefficient or less cost-effective transmission projects.[232]

93. We are unpersuaded by SERTP Sponsors' argument that the Commission failed to satisfy its burden under the first prong of FPA section 206 analysis because it ignored evidence that transmission expansion in SERTP is driven by ''planning processes that proactively anticipate[ ] a changing resource mix and the use of firm 'physical' transmission service—and not by interconnection requests.'' [233] As Order No. 1920 makes clear, the deficiencies of existing transmission planning and cost allocation processes result in various detrimental outcomes reflecting that existing requirements are unjust and unreasonable. Over-reliance on generator interconnection requests to expand the transmission system is just one such example. The Commission noted other existing deficiencies as well, including that the majority of investments in transmission facilities are occurring through local transmission planning processes and in-kind replacements, which focus on the needs of individual transmission provider footprints and miss the potential for more efficient or cost-effective regional transmission facilities.[234]

94. Moreover, although SERTP Sponsors assert that SERTP ''does not suffer from [Order No. 1920's] theoretical deficiencies,'' [235] and Alabama Commission asserts that that the Commission ignored evidence that transmission planning in SERTP ''achieves many, if not most, of the goals in the Final Rule,'' [236] the Commission, in fact, cited evidence that SERTP's transmission planning process suffers from each of the three deficiencies that the Commission identified in Order No. 1920. Record evidence demonstrates that SERTP's regional transmission planning and cost allocation process (1) does not perform a sufficiently long-term assessment of transmission needs; [237] (2) does not adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; [238] and (3) fails to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.[239]

95. Further, Designated Retail Regulators and Undersigned States provide no support for their claim that ''a substantial portion of transmission providers'' are currently conducting ''effective long-term planning.'' [240] Instead, they assert that CAISO, NYISO, Southern Companies, and ''[o]ther regions . . . have sufficient long-term planning'' [241] without explaining how the transmission planning processes in those regions do not suffer from the deficiencies that the Commission identified in Order No. 1920 as necessitating reform of its existing regional transmission planning and cost allocation requirements. Similarly, Designated Retail Regulators' and Undersigned States' conclusion that SPP's transmission planning processes are ''sufficient to meet the Commission's

[226] Order No. 1920, 187 FERC ¶ 61,068 at P 115 & n.282 (citing ITC NOPR 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'')).

[227] *Id.* P 116 (citing AEP NOPR Initial Comments at 11; Nevada Commission NOPR Initial Comments at 7 n.24; PIOs NOPR Initial Comments at 14; Renewable Northwest NOPR Initial Comments at 5; SEIA NOPR Initial Comments at 6). The Commission discussed MISO's MVP initiative, which took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, a 10-year period that does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval. Order No. 1920, 187 FERC ¶ 61,068 at P 116 (citing AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio,* at 39 (2021)).

[228] *Id.* (citing SEIA NOPR Initial Comments at 6; US DOE NOPR Initial Comments at 33).

[229] *Id.* P 118 & n.294.

[230] *Id.* P 118 & n.293.

[231] *Id.* P 122 & nn.309–12 (citing Massachusetts Attorney General ANOPR Initial Comments at 22 (''New England's siloed approach to transmission planning inhibits identification of multi-value solutions.''); PIOs Initial Comments 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 . . . . [M]ultiple quantifiable benefits to transmission . . . are being ignored in the transmission planning process.''); 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.'').

[232] *Id.* P 127 & n.318 (citing New Jersey Commission NOPR 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 NOPR 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'')).

[233] SERTP Sponsors Rehearing Request at 36.

[234] Order No. 1920, 187 FERC ¶ 61,068 at P 109–111.

[235] SERTP Sponsors Rehearing Request at 34 & n.100.

[236] Alabama Commission Rehearing Request at 3.

[237] Order No. 1920, 187 FERC ¶ 61,068 at P 115 (noting that SERTP uses a 10-year transmission planning horizon (citing Southeast PIOs NOPR Initial Comments at 12)).

[238] *Id.* P 118 n.294 (explaining that in 2021, SERTP stated that because it did not receive any proposals for transmission needs driven by Public Policy Requirements for the 2021 planning cycle, it identified no possible transmission needs driven by Public Policy Requirements for further evaluation of potential transmission solutions in that planning cycle (citing SREA NOPR Initial Comment at 25)).

[239] *Id.* P 122 n.312 (''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.'' (quoting SREA NOPR Initial Comments at 24)).

[240] *See* Designated Retail Regulators Rehearing Request at 21; Undersigned States Rehearing Request at 22.

[241] Designated Retail Regulators Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65–66)); Undersigned States Rehearing Request at 23 (citing Order No. 1920, 187 FERC ¶ 61,068 (Christie, Comm'r, dissenting, at PP 65–66)).

desired outcomes'' [242] cites to a single sentence in comments SPP filed nearly two years before the Commission adopted Order No. 1920, in which SPP stated only that it ''believe[d] its current study processes and initiatives [to be] sufficient to meet the Commission's desired outcomes.'' [243] Such unsupported statements about the sufficiency of transmission planning processes in various transmission planning regions similarly fail to establish that those transmission providers' existing transmission planning and cost allocation processes do not suffer the deficiencies that the Commission identified in Order No. 1920. While MISO's regional transmission planning process may satisfy certain of Order No. 1920's requirements, this does not establish that deficiencies in existing regional transmission planning and cost allocation processes are occurring only in ''isolated pockets.''

96. Moreover, SERTP Sponsors do not identify any authority supporting the contention that the Commission cannot make a generic finding under section 206 unless it shows that every transmission provider's OATT is unjust and unreasonable or unduly discriminatory or preferential. Nor are we convinced by SERTP Sponsors' attempts to distinguish *South Carolina Public Service Authority* v. *FERC,* where the court held that ''the Commission may act by generic rule . . . without first finding that the rates charged by individual utilities are unjust or unlawful when it concludes that any tariff violating the rule would have such adverse effects on the interstate gas or energy market as to render it unjust and unreasonable.'' [244] SERTP Sponsors assert that, given ''SERTP's scale and scope and the fact that it does not suffer from [Order No. 1920's] theoretical deficiencies,'' the reasoning of *South Carolina Public Service Authority* v. *FERC* is inapplicable here. However, while we do not need to make specific findings regarding individual transmission providers, we note, as discussed above, that record evidence demonstrates that SERTP does suffer from each of the theoretical deficiencies that the Commission identified in Order No. 1920. Significantly, in finding that existing regional transmission planning and cost allocation requirements are not just and reasonable, the Commission also recognized that ''the present is not a prediction of the future'' [245] in light of the threat, documented by substantial evidence, that, absent Order No. 1920's reforms, 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. That ''the present is not a prediction of the future'' is especially true in a period of rapid change like the electric sector is now experiencing. Given industry trends that the Commission highlighted in Order No. 1920—changing longer-term reliability needs due to more frequent extreme weather events and the increasing share of variable resources entering the resource mix,[246] significantly increasing demand,[247] and changes to the nation's resource mix [248]—even if the identified deficiencies in existing regional transmission planning and cost allocation requirements have yet to manifest clearly in every transmission planning region, we can reasonably predict that they will in the near future. The Commission acted within its authority to prevent that eventuality from materializing.[249]

97. Moreover, the Commission found that the existing regional transmission planning and cost allocation *requirements* are unjust and unreasonable under of the first prong of FPA section 206.[250] While transmission planning regions vary in their specific approaches, and some transmission providers, within their discretion, may have adopted practices that satisfy some of Order No. 1920's requirements, there is no guarantee that these practices will continue in the absence of Order No. 1920's requirements. If transmission providers believe that they already satisfy any of the requirements of Order No. 1920, they may seek to demonstrate that they do so in their compliance filings.

4. The Commission Has the Authority To Conduct a Generic Rulemaking

a. Requests for Rehearing

98. Undersigned States argue that the Commission lacks authority to make rate determinations on a generic, national level.[251] Undersigned States note that under section 206, the Commission has the power to determine, after a hearing held upon its own motion or upon complaint, that the rates charged by a specific utility subject to Commission jurisdiction are unjust, unreasonable, unduly discriminatory, or preferential, and if so, to adjust that rate.[252] Undersigned States claim that this does not authorize the Commission to issue Order No. 1920.[253]

99. Arizona Commission argues that there is no evidence that it has acted in a discriminatory or unfair way while creating rates and processes.[254] Therefore, Arizona Commission argues, Order No. 1920's section 206 finding is unlawful when applied to the Arizona Commission because there must be an individual finding as to the Arizona Commission before section 206 can be applied to it. Arizona Commission states that it is arbitrary and capricious ''to infer any evidence in the record supports the conclusion the [Arizona Commission] has acted in a discriminatory or unfair way.'' [255]

b. Commission Determination

100. We continue to find that the Commission has the authority to institute the reforms adopted in Order No. 1920 and that it was not required to demonstrate that transmission planning and cost allocation processes are unjust, unreasonable, or unduly discriminatory or preferential with respect to specific transmission providers. Rehearing parties' arguments to the contrary seem to rely on a misinterpretation of FPA section 206. Section 206 delegates substantial responsibility to the Commission:

101. Whenever the Commission, after a hearing held upon its own motion or

[242] Designated Retail Regulators Rehearing Request at 22 (citing SPP NOPR Initial Comments at 3); Undersigned States Rehearing Request at 22 (citing SPP NOPR Initial Comments at 3).

[243] SPP NOPR Initial Comments at 3.

[244] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 86 (quoting *Associated Gas Distributors,* 824 F.2d at 1008).

[245] *Id.* at 67 (quoting Order No. 1000–A, 139 FERC ¶ 61,132 at P 65); *see also* Order No. 1000–A, 139 FERC ¶ 61,132 at P 65 (''The Commission is authorized to make rules with prospective effect that will prevent situations that are inconsistent with the FPA from occurring, which means that it is authorized to consider how the future may be different from the present if the rules it proposes are not adopted.'').

[246] Order No. 1920, 187 FERC ¶ 61,068 at P 94.

[247] *Id.* P 95.

[248] *Id.* P 96.

[249] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 64–65, 85 (''[W]hether a threat of unjust or unreasonable rates derives from a practice or the absence thereof, Section 206 empowers the Commission to address it.'').

[250] Order No. 1920, 187 FERC ¶ 61,068 at P 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.'') (emphasis added)).

[251] Undersigned States Rehearing Request at 23.

[252] *Id.* at 23–24 (citing 16 U.S.C. 824e).

[253] *Id.* at 24.

[254] Arizona Commission Rehearing Request at 19.

[255] *Id.* at 19–20.

upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.[256]

102. As the Commission explained in Order No. 1920, and as courts have confirmed, transmission planning and cost allocation processes are ''are practices affecting rates subject to the Commission's exclusive jurisdiction.'' [257] Rehearing parties cite no precedent suggesting that section 206 requires the Commission to act on an individual, utility-by-utility basis, and we are aware of none.

103. Contrary to Undersigned States' argument that the Commission lacks authority to make rate determinations on a generic, national level, courts have consistently interpreted section 206 to allow the Commission to regulate on a national level, through notice-and-comment rulemakings, when the Commission finds systemic issues throughout the industry that cause practices affecting rates charged by public utilities to be unjust, unreasonable, or unduly discriminatory or preferential.[258] Nearly 40 years of precedent has consistently interpreted the Commission's FPA section 206 authority—and the corresponding, nearly identical authority in the Natural Gas Act [259]—as providing the Commission with the authority to ''rely on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution.'' [260] In fact, in interpreting the nearly identical provision of the Natural Gas Act, the D.C. Circuit stated that ''[t]he Commission is not required to make individual findings, however, if it exercises its Natural Gas Act § 5 authority by means of a generic rule.'' [261] The Commission has, time and time again, exercised section 206 authority through generic rulemakings that rely on industry-wide findings rather than region-by-region or utility-specific findings.[262] Indeed, Order No. 1920 itself builds upon existing transmission planning and cost allocation requirements adopted by the Commission through other generally applicable, nationwide rulemakings. Thus, the Commission was not required to make specific findings as to the Arizona Commission or transmission planning and cost allocation processes within Arizona or any given state. Moreover, Order No. 1920's reforms are directed to transmission providers, consistent with the Commission's jurisdiction,[263] and do not require any action by state regulatory authorities.[264] In light of the Commission's authority to act on a generic basis to reform the practices of all transmission providers, the Commission reasonably exercised its broad discretion to proceed by nationwide rulemaking to remedy the deficiencies that it determined in Order No. 1920 render its existing regional transmission planning and cost allocation requirements unjust and unreasonable.[265]

C. The Commission Demonstrated That the Replacement Rate is Just and Reasonable

1. Requests for Rehearing

104. Several rehearing parties argue that the Commission did not demonstrate that the replacement tariff and transmission planning requirements are just and reasonable.[266] According to Designated Retail Regulators, Order No. 1920 ''requires the construction of transmission to socialize the costs of policies of some States and parties over others and shifts the costs caused by interconnecting remotely located generators to everyone,'' but provides ''no analysis showing that the resulting rates are just and reasonable.'' [267] Industrial Customers contend that Order No. 1920 generically asserts, without ''evidence, proof, or data,'' that its reforms ''*should* provide cost savings.'' [268]

105. Designated Retail Regulators also claim that Order No. 1920 contradicts Order Nos. 888 and 890, under which the cost of transmission is generally borne by load. Designated Retail Regulators argue that, in contrast, the final rule promotes the construction of long-haul transmission designed to move energy from remote resources located in one state to load located in another without any contractual or other assurance to the load-serving entity that the remotely located resource will provide firm energy. Designated Retail Regulators contend that, in the absence of a contractual or regulatory requirement to supply firm energy, there is no reasonable rationale that would justify allocating the cost for this transmission to remotely located load.[269] Designated Retail Regulators also argue that remotely located customers who are required to pay for transmission facilities without regulatory or contractual guarantees of receiving firm energy are not beneficiaries, must less cost causers.[270]

106. Industrial Customers argue that Order No. 1920 is arbitrary and capricious and does not reflect reasoned decision-making because it fails to consider and address costs to consumers, which is an essential element of the problem of transmission

[256] 16 U.S.C. 824e.

[257] Order No. 1920, 187 FERC ¶ 61,068 at P 86 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55).

[258] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (upholding Order No. 1000); *TAPS,* 225 F.3d 667, *aff'd sub nom. N.Y.* v. *FERC,* 535 U.S. 1 (upholding Order No. 888).

[259] 15 U.S.C. 717d(a).

[260] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67 (quoting *Interstate Nat. Gas of Am.* v. *FERC,* 285 F.3d at 37; *see also TAPS,* 225 F.3d at 687–88; *Associated Gas Distributors,* 824 F.2d 981; *Wis. Gas Co.* v. *FERC,* 770 F.2d at 1166 & n.36.

[261] *Associated Gas Distributors,* 824 F.2d at 1008. It is ''well settled that comparable provisions of the Natural Gas Act and [FPA] are to be construed *in pari materia.*'' *Ky. Utils. Co.* v. *FERC,* 760 F.2d 1321, 1325 n.6 (D.C. Cir. 1985).

[262] *See, e.g., TAPS,* 225 F.3d 667 (upholding Order No. 888, which was promulgated under FPA section 206 and premised on general systemic conditions rather than evidence regarding individual utilities); *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (same for Order No. 1000); *Elec. Storage Participation in Mkts. Operated by Reg'l Transmission Organs. and Indep. Sys. Operators,* Order No. 841, 83 FR 9580 (Mar. 6, 2018), 162 FERC ¶ 61,127, at P 21 (2018), *order on reh'g,* Order No. 841–A, 167 FERC ¶ 61,154 (2019), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 964 F.3d 1177 (D.C. Cir. 2020) (*NARUC*); Order No. 890, 118 FERC ¶ 61,119 at PP 41–43.

[263] Order No. 1920, 187 FERC ¶ 61,068 at PP 1 n.2, 253.

[264] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 263 (''[T]his final rule directly regulates transmission planning and cost allocation processes, . . . directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201.'').

[265] *See Wis. Gas Co.* v. *FERC,* 770 F.2d at 1157 (''An administrative agency must be equipped to act either by general rule or individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity. The choice made between proceeding by general rule or by individual, *ad hoc* litigation is one that lies primarily in the informed discretion of the administrative agency.'' (alterations omitted) (quoting *SEC* v. *Chenery Corp.,* 332 U.S. 194, 202–03 (1947)).

[266] Designated Retail Regulators Rehearing Request at 22–23; Undersigned States Rehearing Request at 23.

[267] Designated Retail Regulators Rehearing Request at 22–23; *see also* Undersigned States Rehearing Request at 23 (similar).

[268] Industrial Customers Rehearing Request at 20.

[269] Designated Retail Regulators Rehearing Request at 23.

[270] *Id.* at 23–24.

planning and cost allocation.[271] Arizona Commission echoes this argument and contends that Order No. 1920 fails to protect consumers and will saddle ratepayers with trillions of dollars in increased rates in coming years, resulting in unfair rates.[272] Arizona Commission adds that the ''several factors'' that Order No. 1920 requires transmission providers to ''consider[ ] in transmission planning and cost allocation'' should have included fairness, reasonableness of cost, or consideration of who caused the cost, as mandated by the FPA.[273]

2. Commission Determination

107. We continue to find that the replacement regional transmission planning and cost allocation requirements that the Commission adopted in Order No. 1920 are just and reasonable.[274] We disagree with rehearing parties' arguments that the Commission did not demonstrate that the replacement rate is just and reasonable, as it appears that these arguments may mischaracterize Order No. 1920. Designated Retail Regulators argue that Order No. 1920 ''requires the construction of transmission to socialize the costs of the policies of some States and parties over others and shifts the costs caused by interconnecting remotely located generators to everyone.'' [275] Like Order No. 1000, Order No. 1920's ''transmission planning reforms are concerned with process, and are not intended to dictate substantive outcomes.'' [276] Order No. 1920 specifically provided that ''[t]he regional transmission planning requirements and cost allocation requirements in this final rule, 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.'' [277]

108. Moreover, Order No. 1920 did not change the Commission's cost causation requirements and does not contradict Order Nos. 888 and 890, under which the cost of transmission is generally borne by load.[278] Order No. 1920 reiterated 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.'' [279] Order No. 1920 further stated that ''[n]othing in this final rule requires states to subsidize other states' public policies and, indeed, this final rule 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.'' [280] Thus, ''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.'' [281] For these reasons, we also disagree with Designated Retail Regulators' argument that Order No. 1920 contradicts Order Nos. 888 and 890. Nonetheless, we believe certain clarifications discussed further below will alleviate Designated Retail Regulators' and Undersigned States' concerns regarding Order No. 1920's impact on multi-state cost allocation.[282]

109. We are similarly unpersuaded by Designated Retail Regulators' assertion that the Commission failed to satisfy its burden under the second prong of FPA section 206 because, under Order No. 1920, ''there is no reasonable rationale that would justify . . . remotely located customers being required to pay for transmission facilities without regulatory or contractual guarantees of receiving firm energy.'' [283] The physics of an interconnected electric transmission system are such that even customers distant from new Long-Term Regional Transmission Facilities and without specific contractual arrangements with such facilities *may* benefit from those facilities.[284] And any proposed cost allocation method for Long-Term Regional Transmission Facilities *must* allocate the costs of a new Long-Term Regional Transmission Facility in a manner at least roughly commensurate with the estimated benefits of the facility.[285] Beyond arguing that Order No. 1920 contradicts Order Nos. 888 and 890, Designated Retail Regulators do not argue that the Commission lacks authority to mandate the allocation of costs where there is no contractual or regulatory requirement to supply firm energy, and we do not believe that such a limitation exists.[286]

110. Additionally, the Commission found that Order No. 1920's requirements—that transmission providers conduct Long-Term Regional Transmission Planning that will ensure the identification, evaluation, and selection, as well as the allocation of costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs—will address the deficiencies in the existing regional transmission planning and cost allocation requirements. Furthermore, the Commission determined, these requirements will promote enhanced reliability and more efficient or cost-effective transmission solutions, which will help to ensure just and reasonable rates.[287] The Commission's finding was based on consideration of the record and reasonable economic predictions,

[271] Industrial Customers Rehearing Request at 19–20 (citing *State Farm,* 463 U.S. at 43).

[272] Arizona Commission Rehearing Request at 20.

[273] *Id.* at 21.

[274] Order No. 1920, 187 FERC ¶ 61,068 at PP 134–138.

[275] Designated Retail Regulators Rehearing Request at 22–23; *see also* Undersigned States Rehearing Requests at 23 (similar).

[276] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 58 (quoting Order No. 1000–A, 139 FERC ¶ 61,132 at P 188); *see infra* Statutory Authority section.

[277] Order No. 1920, 187 FERC ¶ 61,068 at P 232.

[278] *See infra* Federal/State Division of Authority section.

[279] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 87; Order No 1000, 136 FERC ¶ 61,051 at P 10; *ICC* v. *FERC I,* 576 F.3d at 476); *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 1297 (''Any cost allocation method(s) that transmission providers propose . . . must allocate costs in a manner that is at least roughly commensurate with estimated benefits . . . .'').

[280] *Id.* P 267 (citing *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)); *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 280 (''[T]he final rule categorically does not require states to subsidize other states' public policies or generation decisions,'' but instead, ''consistent with the cost causation principle, [the] final rule 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 must be roughly commensurate with the benefits they receive.'').

[281] *Id.* P 282.

[282] *See supra* Concerns Regarding Cost Causation section.

[283] Designated Retail Regulators Rehearing Request at 23–24.

[284] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 85 (''Entities that contract for service on the transmission grid cannot choose to affect only the transmission facilities for which they have entered into a contract and cannot claim that they are not using or benefiting from such transmission facilities simply because they did not enter a contract to use them.'' (quoting Order No. 1000–A, 139 FERC ¶ 61,132 at P 561 (cleaned up)).

[285] Order No. 1920, 187 FERC ¶ 61,068 at P 1305.

[286] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 84 (reasoning that the text of section 206 does not limit ''cost allocation to entities with preexisting commercial relationships,'' and instead ''empowers the Commission to fix 'any rate' 'demanded, observed, charged, or collected by any public utility for any transmission . . . subject to the jurisdiction of the Commission,' and 'any . . . practice' 'affecting such rate.''').

[287] Order No. 1920, 187 FERC ¶ 61,068 at P 134.

which indicate that long-term, forward-looking, and more comprehensive regional transmission planning that identifies Long-Term Transmission Needs helps transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to meet those needs.[288] These points are especially true considering the clarifications we adopt below.

111. For instance, the Commission was persuaded by empirical evidence demonstrating the success of MISO's Long-Range Transmission Plan in delivering more efficient or cost-effective transmission solutions.[289] By addressing public policy, economic, and reliability transmission planning needs simultaneously through its MVP category, MISO eliminated 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.[290] The Commission noted that the cost savings that MISO experienced were the direct product of more comprehensive, longer-term regional transmission planning.[291]

112. The Commission also made several reasonable economic predictions regarding the effects of Order No. 1920. It was, for instance, reasonable for the Commission to predict that the transmission planning reforms adopted in Order No. 1920, which bear many similarities to MISO's MVP process, will have similar results and that longer-term regional transmission planning that considers a wider array of relevant factors will yield a more efficient or cost-effective selection of regional transmission facilities to meet Long-Term Transmission Needs, thus saving customers money.[292] The Commission reasonably concluded, and we continue to find, that forgoing this type of planning and requiring customers to bear the costs of relatively inefficient and less cost-effective transmission development results in unjust and unreasonable Commission-jurisdictional rates.[293]

113. We understand concerns raised by Arizona Commission and Industrial Customers that Order No. 1920 fails to protect consumers and will impose substantial costs on ratepayers.[294] However, in Order No. 1920, the Commission found that the *existing* approach to regional transmission planning is resulting in customers paying more than necessary or appropriate to meet their transmission needs, forgoing benefits that outweigh their costs, or some combination thereof.[295] Thus, the Commission adopted reforms in Order No. 1920 that are necessary to ensure that regional transmission planning processes identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, so that customers do not continue to pay for relatively inefficient or less cost-effective transmission development.[296] Addressing costs to ratepayers was central to the reforms that the Commission adopted in Order No. 1920, and the Commission cited evidence that more comprehensive, longer-term regional transmission planning results in significant cost saving for customers.[297] Further, we disagree with Industrial Customers' argument that Order No. 1920 states, without ''evidence, proof, or data,'' that its reforms ''*should* provide cost savings.'' [298] As discussed above, the Commission cited robust and diverse evidence to support its finding that the type of regional transmission planning required by the final rule will likely result in cost savings to customers relative to the status quo approach.[299] Nonetheless, we believe the clarifications adopted herein will alleviate Industrial Customers' concerns.

114. We also recognize Arizona Commission's argument that the ''several factors'' that Order No. 1920 requires transmission providers to ''consider[ ] in transmission planning and cost allocation'' should have included fairness or reasonableness of cost or consideration of who caused the cost.[300] We believe these factors are appropriately accounted for in other stages of the regional transmission planning and cost allocation process. For example, the evaluation process considers reasonableness of costs by considering cost estimates for, as well as the benefits of, identified Long-Term Regional Transmission Facilities.[301] The cost allocation process also considers fairness and cost causation, as ''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.'' [302] However, we believe certain clarifications adopted herein will address the concerns underlying Arizona Commission's argument.

D. The Commission's Section 206 Findings Were Not Circular

1. Requests for Rehearing

115. Industrial Customers and SERTP Sponsors argue that the Commission's findings under the two prongs of section 206 are circular.[303] According to Industrial Customers, rather than cite specific record evidence or specify the problems that the Commission seeks to address, the Commission relies on the benefits of Order No. 1920's remedy—*e.g.,* longer-term, more comprehensive regional transmission planning—to support its threshold finding under the first prong of FPA section 206.[304] Industrial Customers thus assert that Order No. 1920 relies on ''circular reasoning,'' whereby the Commission develops a desired solution and then finds that the current absence of that desired solution renders the status quo unjust and unreasonable.[305] This approach, Industrial Customers contend, does not reflect reasoned decision making.[306] Further, Industrial Customers argue that proceeding in this fashion exceeds the Commission's authority under the FPA and could allow the Commission to ''essentially legislate to achieve any desired

[288] *Id.* PP 135–138 (citing ACEG NOPR Initial Comments 53–56; Brattle-Grid Strategies Oct. 2021 Report at 7 & nn.13–14; Clean Energy Associations NOPR Initial Comments at 25–27; Exelon NOPR Initial Comments 5; ITC NOPR Initial Comments at 44; MISO NOPR Initial Comments at 88; MTEP2017 Review at 6, 8; New Jersey Commission NOPR Initial Comments at 4; PIOs NOPR Initial Comments at 10, 35; SEIA NOPR Initial Comments 25–26).

[289] *Id.* P 135.

[290] *Id.* (MTEP2017 Review at 6).

[291] *Id.* P 136.

[292] *See id.*

[293] *Id.* P 112.

[294] *See* Arizona Commission Rehearing Request at 20–21; Industrial Customers Rehearing Request at 19–20.

[295] Order No. 1920, 187 FERC ¶ 61,068 at P 117.

[296] *Id.* P 113; *see also id.* P 136 (''[R]egional transmission planning and cost allocation reforms [adopted in Order No. 1920] will benefit customers by leading to more efficient or cost-effective transmission investment, thereby helping to ensure just and reasonable rates.'' (citations omitted)).

[297] *E.g., Id.* P 135 (citing MTEP2017 Review at 6).

[298] Industrial Customers Rehearing Request at 20 (emphasis in original).

[299] *See supra* The Commission Adequately Supported Its Determination on Step One of Section 206 section; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 135 & n.346 (citing a projection that proactive, portfolio-based transmission planning in PJM could ultimately save ratepayers over $30 billion compared to the status quo).

[300] Arizona Commission Rehearing Request at 21.

[301] Order No. 1920, 187 FERC ¶ 61,068 at PP 955, 958.

[302] *Id.* P 267; *see BNP Paribas Energy Trading GP* v. *FERC,* 743 F.3d 264, 268–69 (D.C. Cir. 2014) (''[T]he cost causation principle itself manifests a kind of equity.'').

[303] Industrial Customers Rehearing Request at 13–15; SERTP Sponsors Rehearing Request at 29–32, 34–35.

[304] Industrial Customers Rehearing Request at 13.

[305] *Id.* at 14.

[306] *Id.* at 15.

outcome.'' [307] Industrial Customers assert that the D.C. Circuit has previously determined that the Commission failed to meet its section 206 burden and therefore committed error by ''beg[inning] with the remedy to show that the *status quo* is not just and reasonable.'' [308]

116. SERTP Sponsors claim that Order No. 1920's broad conclusion that the regional transmission planning processes conducted by all transmission providers in each transmission planning region are unjust, unreasonable, unduly discriminatory, and preferential is based on the absence of the unique form of long-term regional transmission planning that meets the Commission's current view of what a regional transmission planning process should be.[309] SERTP Sponsors also contend that Order No. 1920 assumes that all regions follow the same generic approach and, while the Commission's *pro forma* transmission planning requirements may be subject to improvement, the Commission has not satisfied its burden of showing that the SERTP regional transmission planning process is unjust and unreasonable.[310]

117. SERTP Sponsors assert that Order No. 1920 imposes its preferred solution in line with the Commission's vision instead of addressing a real need for reform specific to the SERTP regional transmission planning process, thereby imposing a ''solution in search of a problem.'' [311] SERTP Sponsors argue that, in doing so, the Commission misapplied section 206 by collapsing the two-step standard into one step, echoing the mistake described in *Emera Maine.*[312] SERTP Sponsors contend that Order No. 1920 does not demonstrate widespread failures in transmission planning practices, but rather theorizes potential inadequacies in meeting the Commission's desired outcomes.[313] SERTP Sponsors aver that Order No. 1920's discussion of the growing need for transmission investments and perceived insufficiencies of current planning standards does not prove that existing processes fail to meet the evolving demands of the electric grid.[314] SERTP Sponsors allege that the SERTP process has been highly efficient, and that its integrated resource plan and request for proposal-driven transmission planning and other similar processes effectively address the Commission's concerns regarding siloed planning, lack of scenario planning, and local versus regional project focus.[315]

118. SERTP Sponsors argue that Order No. 1920 incorrectly characterizes SERTP's and other similar transmission planning regions' transmission planning processes as deficient due to the absence of alternative regional transmission facilities selected since the implementation of Order No. 1000.[316] SERTP Sponsors contend that the fact that no regional transmission projects have been selected underscores the success of existing integrated resource plan/request for proposal-driven planning systems rather than a failure or deficiency in the regional transmission planning process.[317] SERTP Sponsors also contend that the success of the Southeast's process has been confirmed by the absence of a National Interest Electric Transmission Corridor (NIETC) designation in the Southeast.[318] SERTP Sponsors state that Order No. 1920's attempt to characterize this success as a deficiency collapses the first and second steps of section 206 in the way that the courts have struck down in the past and means that this aspect of the order is unsupported by substantial evidence and is otherwise arbitrary and capricious.[319]

2. Commission Determination

119. We conclude that the Commission's section 206 findings, identifying specific deficiencies in regional transmission planning and cost allocation requirements at prong one and establishing specific new requirements at prong two, are—as they are required to be—closely related, in contrast to rehearing parties' arguments. Industrial Customers and SERTP Sponsors' arguments on this point [320] both rely on *Emera Maine,* in which the D.C. Circuit found that the Commission erred in basing its determination that the utility's existing 11.14% base return on equity (ROE) was unjust and unreasonable because it exceeded the 10.57% ROE that the Commission had concluded was the just and reasonable base ROE.[321] The court explained that the Commission must first determine that an existing rate is unjust and unreasonable (prong one) before it imposes a replacement rate (prong two).[322] Industrial Customers and SERTP Sponsors argue that, like the Commission's error in *Emera Maine,* Order No. 1920 based its finding that the status quo is unjust and unreasonable on the absence of the Commission's specific desired replacement.[323]

120. When acting under section 206, the Commission must make two findings: (1) that the existing rate, or a practice affecting a rate, is unjust, unreasonable, or unduly discriminatory or preferential; and (2) that the Commission's replacement rate, or practice affecting a rate, is just and reasonable and not unduly discriminatory or preferential.[324] As discussed above, the Commission appropriately made both findings in Order No. 1920, so *Emera Maine* is inapposite.

121. The Commission's findings under the first prong of section 206 do not rely on the specific replacement rate that it created in Order No. 1920. Rather, the Commission's findings under the first prong of section 206 rest on deficiencies, identified based on substantial record evidence, in existing regional transmission planning and cost allocation requirements, specifically that they are insufficiently long-term, forward-looking, and comprehensive. The fact that there is a relationship between the deficiencies identified in prong one and the new requirements established as the just and reasonable replacement under prong two of FPA section 206 demonstrates that the replacement regional transmission planning and cost allocation requirements are appropriately tailored toward remedying the deficiencies that the Commission identified in existing regional transmission planning and cost allocation requirements.

122. Order No. 1920 made explicit findings that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential in several respects.[325] First, with regard to long-term regional transmission planning, the Commission noted that most transmission planning regions do not plan beyond a 10-year time horizon.[326]

[307] *Id.* at 14.

[308] *Id.* at 15 (citing *Emera Me.* v. *FERC,* 854 F.3d 9, 22, 25 (D.C. Cir. 2017)).

[309] SERTP Sponsors Rehearing Request at 30.

[310] *Id.* at 31–32.

[311] *Id.* at 30.

[312] *Id.* (citing *Emera Me.,* 854 F.3d at 22–26).

[313] *Id.* at 34.

[314] *Id.*

[315] *Id.* at 32.

[316] *Id.* at 35.

[317] *Id.*

[318] *Id.* at 35–36 (citation omitted).

[319] *Id.* at 36 & n.104 (citations omitted).

[320] Industrial Customers Rehearing Request at 15 (citing *Emera Maine,* 854 F.3d at 9, 22, 25); SERTP Sponsors Rehearing Request at 30 (citing the same).

[321] *Emera Maine,* 854 F.3d at 25–26.

[322] *Id.* at 25–26.

[323] Industrial Customers Rehearing Request at 15; SERTP Sponsors Rehearing Request at 30.

[324] 16 U.S.C. 824e(a), (b); *Pub. Serv. Elec. & Gas Co.* v. *FERC,* 989 F.3d at 13.

[325] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[326] Order No. 1920, 187 FERC ¶ 61,068 at P 115; *see supra* Unjust, Unreasonable, and Unduly

The Commission's finding that a 10-year transmission planning horizon is insufficient does not rely on the Commission's finding that 20 years is the just and reasonable time horizon for Long-Term Regional Transmission Planning. The reasoning underlying the finding that a 10-year transmission planning horizon is insufficient would hold true even if the Commission had determined a different number (*e.g.,* 17 or 25 or 31 years) was the just and reasonable replacement. This result is in stark contrast to *Emera Maine,* where the Commission's finding that the existing base ROE was unjust and unreasonable rested entirely on the finding that it did not equal the Commission's replacement ROE.[327] Second, the Commission found, based on substantial evidence, that existing regional transmission planning and cost allocation requirements fail to require transmission providers to adequately account for known determinants of Long Term Transmission Needs.[328] Third, the Commission found, also based on substantial evidence, that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider a sufficiently broad and standard set of benefits of regional transmission facilities.[329] These findings are not based on the precise list of determinants or benefits that the Commission identified in establishing the replacement under of the second prong under FPA section 206, but rather on the conclusion that most transmission providers focus too narrowly on only some determinants and benefits, ignoring other relevant factors, which leads to relatively inefficient or less cost-effective transmission development.[330] Lastly, the Commission's findings that existing cost allocation requirements are deficient relied on the fact that the Commission's previous cost allocation requirements were tailored to the Order No. 1000 regional transmission planning requirements, but Order No. 1920's new requirements for Long-Term Regional Transmission Planning account for multiple drivers of Long-Term Transmission Needs and result in Long-Term Regional Transmission Facilities that produce a broader set of benefits, and therefore warrant a different approach to cost allocation for such transmission facilities.[331]

123. We also disagree with SERTP Sponsors' contention that Order No. 1920 assumes that all transmission planning regions follow the same generic approach.[332] To the contrary, and as discussed above, Order No. 1920 highlights deficiencies in regional transmission planning processes around the country.[333] Moreover, the Commission found that its existing regional transmission planning and cost allocation *requirements* are unjust and unreasonable.[334] While regions vary in specific approaches, those approaches are all based on the same requirements. It is those requirements that we continue to find are unjust and unreasonable given the record before us.

124. Additionally, although SERTP Sponsors contend that SERTP's process is highly efficient,[335] the Commission is not required to make findings with respect to individual transmission owners' transmission planning and cost allocation processes to remedy the deficiencies that it determined in Order No. 1920 render its existing regional transmission planning and cost allocation requirements unjust and unreasonable.[336] We also are not persuaded by SERTP Sponsors' argument that the absence of regional transmission facilities selected since the implementation of Order No. 1000 necessarily demonstrates the success of integrated resource plan/request for proposal-driven planning systems instead of a deficiency in regional transmission planning processes.[337] Integrated resource plan/request for proposal-driven planning systems do not replace the need for effective regional transmission planning, as only regional transmission planning ensures consideration of more efficient or cost-effective transmission facilities across utility footprints. We continue to 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,'' which 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.'' [338]

IV. Statutory Authority

A. Order No. 1920 Determination

125. In Order No. 1920, the Commission reaffirmed its conclusion in the NOPR that it was acting within its 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.[339] In doing so the Commission found—and noted that no commenter disputed—that 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.[340]

126. The Commission disagreed with arguments that the requirements adopted in Order No. 1920 infringe on

Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[327] *Emera Maine,* 854 F.3d at 22.

[328] Order No. 1920, 187 FERC ¶ 61,068 at P 118; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[329] Order No. 1920, 187 FERC ¶ 61,068 at P 122; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[330] Order No. 1920, 187 FERC ¶ 61,068 at PP 122–123.

[331] *Id.* PP 124–126; *see supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[332] SERTP Sponsors Rehearing Request at 28, 31–34.

[333] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[334] Order No. 1920, 187 FERC ¶ 61,068 at P 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.'') (emphasis added)).

[335] SERTP Sponsors Rehearing Request at 32.

[336] *See supra* The Commission Has the Authority to Conduct a Generic Rulemaking section. Moreover, we note that the record reflects disagreement on this point. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 56 (''SREA argues that 'transmission planning in the Southeast has many holes and is threadbare.''); *id.* P 115 (''[C]ommenters point out that . . . SERTP . . . plan[s] using a 10-year transmission planning horizon.''); *id.* P 333 (''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.''); *id.* P 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 benefits . . . [and] contends that [those] process[es] can only address these four categories on a utility-by-utility basis and, thus, [are] unable to plan for transmission facilities across utilities or transmission planning regions by nature.'').

[337] SERTP Sponsors Rehearing Request at 35.

[338] Order No. 1920, 187 FERC ¶ 61,068 at P 112.

[339] Order No. 1920, 187 FERC ¶ 61,068 at P 253.

[340] *Id.* (citing 16 U.S.C. 824e; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55–59; *Emera Me.* v. *FERC,* 854 F.3d at 673–74).

the authority reserved to the states by FPA section 201 or are otherwise barred by certain prudential or constitutional principles.[341] Noting that it believed that these concerns mainly arose from misunderstandings regarding the substance of Order No. 1920, the Commission explained that Order No. 1920 builds on more than a quarter century of Commission action on transmission planning and cost allocation, which courts have affirmed notwithstanding objections similar to those presented to Order No. 1920, by addressing specific gaps in the existing framework.[342] It emphasized that Order No. 1920 ''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.'' [343] To the contrary, Order No. 1920 ''directly regulates transmission planning and cost allocation processes, . . . directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201.'' [344] Moreover, Order No. 1920 ''is not aiming to *indirectly* regulate any matter reserved to the states by FPA section 201'' but, instead, only to improve existing transmission and cost allocation processes to address identified deficiencies with those processes.[345]

127. The Commission explained that these considerations confirmed that Order No. 1920 was well within its authority under the FPA, particularly in light of U.S. Supreme Court precedent in *EPSA.*[346] Applying that decision, the Commission stated that ''what 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.'' [347] In Order No. 1920, the Commission ''aim[ed] 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.'' [348] Likewise, and consistent with *EPSA,* the Commission found that every aspect of Order No. 1920 ''happens exclusively as part of a process that is subject to the Commission's jurisdiction and governs exclusively how those processes work.'' [349] The Commission further explained that Order No. 1920 does not require that transmission providers achieve any particular substantive outcome of the transmission planning process, aim to alter states' or the nation's generation mix, or otherwise regulate matters within state jurisdiction.[350]

128. The Commission further explained that, applying *EPSA,* Order No. 1920 was within its jurisdiction to regulate the practices affecting the rates for the transmission of electric energy in interstate commerce, notwithstanding that the rule might have effects on matters reserved to state jurisdiction under FPA section 201.[351] The Commission explained that such effects are inevitable—a ''fact of economic life'' as the Supreme Court put it—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.'' [352]

129. The Commission therefore disagreed with arguments that Order No. 1920 unlawfully intruded on areas of reserved state authority under FPA section 201.[353] The Commission stated that Long-Term Regional 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).'' [354] It stated that the effects of such planning on areas of state authority, however, do not divest the Commission of the jurisdiction Congress conferred on it to regulate the transmission of electric energy in interstate commerce.[355]

130. The Commission was also not persuaded by arguments that Order No. 1920 was unlawful under the ''major questions doctrine.'' [356] It found that commenters were misinterpreting the Supreme Court's decision in *West Virginia* v. *EPA* as suggesting that, in every instance, agency regulations affecting energy policy and the generation mix are ''major questions'' requiring direct authorization from Congress.[357] Rather, the Commission stated that the Supreme Court in that decision considered a specific United States Environmental Protection Agency (EPA) action in light of a particular statutory provision and concluded that this action implicated the major questions doctrine based on a variety of factors specific to that context.[358] The Commission noted that commenters had not analyzed whether Order No. 1920 would, based on the factors the Supreme Court examined, constitute a major question; when the Commission

[341] *Id.* P 254.

[342] *Id.* PP 254–256.

[343] *Id.* P 254; *see also id.* P 257 (''[T]his rule does not mandate development of any particular transmission facility.''); *id.* P 258 (''[T]his final rule 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.''); *id.* P 259 (explaining that Order No. 1920 ''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''); *id.* P 266.

[344] *Id.* P 263.

[345] *Id.; see also id.* P 265 (''[T]his 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.'').

[346] *See id.* PP 264–266.

[347] *Id.* P 265.

[348] *Id.*

[349] *Id.* P 266 (quotation marks omitted).

[350] *Id.; cf. id.* P 267 (also rejecting arguments that Order No. 1920 required states to subsidize other state's public policies, explaining that Order No. 1920 required following long-extant precedent that transmission customers need only pay costs that are ''roughly commensurate'' with the benefits received from a regional transmission facility).

[351] *Id.* P 264 (explaining that such effects are of '''no legal consequence''' (quoting *EPSA,* 577 U.S. at 281)); *see id.* P 262 n.612 (quoting *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, [16 U.S.C.] 824(b) imposes no bar.'' (emphasis added))).

[352] *Id.* (quoting *EPSA,* 577 U.S. at 281); *see id.* P 272 (''We acknowledge that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable.'').

[353] *See id.* PP 271–274.

[354] *Id.* P 272 (noting also that existing transmission planning processes already take these assumptions into account, and that Order No. 1920 ''simply modifies the scope and duration of these assumptions'' to ensure more effective transmission planning).

[355] *See id.* PP 264, 271–272.

[356] *See id.* PP 275–279.

[357] *Id.* PP 275–276.

[358] *Id.* P 276 (noting that these factors ''include[d] 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'' (citing *W.V.* v. *EPA,* 597 U.S. 697, 710, 724–25, 729, 731–32 (2022) (*West Virginia*)).

considered those factors, it concluded that Order No. 1920 would not implicate the major questions doctrine.[359] Among other things, the Commission found that Order No. 1920, as an incremental improvement building on past regulation, did not represent a transformative expansion of the Commission's regulatory authority and did not have vast economic or political significance; [360] did not resemble EPA's assertion of authority related to the electric system; [361] was not reliant on a ''backwater'' statutory provision; and was not promulgated notwithstanding Congress's repeated rejection of legislation to enact reforms similar to those in the rule.[362]

131. The Commission also disagreed with arguments that Order No. 1920 effectively required certain states to subsidize other states' vision of what resources should be used in electricity generation and, therefore, violated the Constitution's ''equal sovereignty doctrine.'' [363] Here, the Commission again explained that Order No. 1920 ''categorically does not require states to subsidize other states' public policies or generation decisions,'' but rather was consistent with longstanding cost-causation principles.[364] Moreover, the Commission pointed out that no court has ever applied the equal sovereignty doctrine invoked by commenters as a limit on Congress's Article I powers, including legislation enacted under the Commerce Clause, such as the FPA.[365]

B. Federal/State Division of Authority

1. Requests for Rehearing

132. Several of the requests for rehearing argue that Order No. 1920 exceeds the Commission's statutory authority under FPA section 206 and is, therefore, unlawful.[366] Many of these requests for rehearing acknowledge the Commission's authority under the FPA over ''the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce.'' [367] However, rehearing parties argue that the Commission's jurisdiction ''extend[s] only to those matters which are not subject to regulation by the States'' and that the Commission, with certain exceptions, ''shall not have jurisdiction . . . 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.'' [368] Undersigned States and Designated Retail Regulators also state that FPA section 215(i)(3) reserves jurisdiction to the states over the ''safety, adequacy, and reliability of electric service.'' [369] Designated Retail Regulators aver that the Commission's authority is limited by the National Interest Electric Transmission Corridor process.[370]

133. Several rehearing requests posit that Order No. 1920 exceeds the Commission's authority because it invades or undermines state authority over the choice of generating resources maintained or constructed within each state's jurisdiction.[371] Undersigned States and Designated Retail Regulators argue that Order No. 1920 ''puts into place planning processes that will favor renewables over other generation and ignore the combined generation/transmission benefits that other solutions could provide.'' [372] They argue that this will result in ''shift[ing] costs to deliver those renewables to customers that do not cause those costs to be incurred and that have selected other generation options with different transmission requirements.'' [373] In this vein, Undersigned States and Designated Retail Regulators assert that ''[r]equiring customers in states to pay for infrastructure to support the public policies and generation resource mixes chosen by other states, without demonstrable benefits to that load, would be a major intrusion on the States' right to choose the resources that best fit their public policies.'' [374]

134. Many of the other arguments challenging the Commission's statutory authority proceed along similar lines. Alabama Commission argues that the Commission in Order No. 1920 is ''putting a 'thumb on the scale' and intruding on resource selection in Alabama.'' [375] Georgia Commission contends that in Order No. 1920 the Commission is acting as a national integrated resource planner, attempting to change the future generation mix,[376] and will require states to subsidize the renewable generation policies of other states.[377] Arizona Commission argues that the Commission lacks ''jurisdiction to impose mandated energy policies for intrastate distribution or to foist costs on rate payers for costs created in other

[359] *See id.* PP 277–279.

[360] *See id.* PP 277–278.

[361] *Id.* P 279.

[362] *See id.*

[363] *See id.* PP 280–282.

[364] *Id.* P 280.

[365] *See id.* P 281 (noting that the FPA, in turn, ''empowers the Commission to regulate the rates and practices affecting rates for the transmission of electricity in interstate commerce'').

[366] *See* Undersigned States Rehearing Request at 2–3, 6, 10–13, 17; Designated Retail Regulators at 2–3, 6, 11–15, 18; Alabama Commission Rehearing Request at 5; Georgia Commission Rehearing Request at 3–4; Arizona Commission Rehearing Request at 2, 9–12, 15; Idaho Commission Rehearing Request at 2, 4–5; Montana Commission Rehearing Request at 1–4; Wyoming Commission Rehearing Request at 1–4; Utah Commission Rehearing Request at 1, 3–7; West Virginia Commission Rehearing Request at 3–4, 10–12.

[367] 16 U.S.C. 824(b)(1); *see also* 16 U.S.C. 824d(a), 824e(a); Undersigned States Rehearing Request at 10–11 (arguing that the FPA is ''primarily, and perhaps exclusively, an *economic* regulation statute''); Designated Retail Regulators at 12 (same); Alabama Commission Rehearing Request at 5; Arizona Commission Rehearing Request at 10; Utah Commission Rehearing Request at 3.

[368] 16 U.S.C. 824(a), (b)(1); *see* Undersigned States Rehearing Request at 11; Designated Retail Regulators at 12–13; Alabama Commission Rehearing Request at 5 (asserting that the Commission's jurisdiction does not extend to ''electric power generation, transmission siting, distribution, retail supply, and service models,'' including ''oversight of the IRP process and the associated selection of resources to provide reliable retail service''); Arizona Commission Rehearing Request at 10–11; Idaho Commission Rehearing Request at 4; Montana Commission Rehearing Request at 2–3.

[369] 16 U.S.C. 824o(i)(3); Undersigned States Rehearing Request at 11; Designated Retail Regulators Rehearing Request at 13.

[370] Designated Retail Regulators Rehearing Request at 18–19 (citing 16 U.S.C. 824p).

[371] *See* Undersigned States Rehearing Request at 11–13 (citing *Pac. Gas & Elec. Co.* v. *State Energy Res. Conservation & Dev. Comm'n,* 461 U.S. 190, 212 (1983); *Nw. Cent. Pipeline Corp.* v. *State Corp. Comm'n of Kan.,* 489 U.S. 493, 522 (1989); *Monongahela Power Co.,* 40 FERC ¶ 61,256, at 61,861 (1987); *Calpine Corp.* v. *PJM Interconnection, L.L.C.,* 171 FERC ¶ 61,035 (2020) (Glick, Comm'r, dissenting at P 5)); Designated Retail Regulators Rehearing Request at 13–14; Idaho Commission Rehearing Request at 4; Utah Commission Rehearing Request at 3–5; West Virginia Commission Rehearing Request at 11; Arizona Commission Rehearing Request at 10–11; *cf. id.* at 2–3 ('''The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities.''' (quoting *Piedmont Envt'l Council* v. *FERC,* 558 F.3d 304, 310 (4th Cir. 2009)).

[372] Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14–15; *see also* Undersigned States Rehearing Request at 3–4 (arguing that Order No. 1920's ''building-block concepts ('Sufficiently long-term,' 'Long-Term Transmission Needs,' 'known determinants of Long-Term Transmission Needs,' the 'broader set of benefits,' and particularly, the inputs to this elaborate scheme) mandate new planning processes for transmission facilities that are designed to (1) move remote renewables over long distances and (2) socialize their costs''); *id.* at 27–29; Designated Retail Regulators Rehearing Request at 3–4, 27–28 (similar).

[373] Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14–15; *see also* Undersigned States Rehearing Request at 33–34.

[374] Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 14; *see also id.* at 38 (''FERC has no statutory authority to pick winners and losers among differing types of generation or use the cost allocation process as an alternative means to dilute financial responsibility for policy decisions.'').

[375] Alabama Commission Rehearing Request at 5.

[376] Georgia Commission Rehearing Request at 3–4 (arguing that Order No. 1920 violates states' reserved decision-making power by requiring that they ''measure their long-term transmission plans against seven factors identified in the Order,'' because these factors allegedly favor certain policies and projects).

[377] *Id.* at 5–6.

states.'' [378] Idaho Commission asserts that certain of the categories of factors that transmission providers must consider in developing Long-Term Scenarios will ''disproportionately favor certain projects in the planning process, provide disparate treatment to states' policy goals, affect resource planning and selection at the state level, and infringe on states' authority with respect to generation.'' [379] Montana Commission, Wyoming Commission, and West Virginia Commission argue that, absent a voluntary State Agreement Process, the cost allocation approach in Order No. 1920 ensures that nonconsenting states will be swept up in their neighbors' preferred policy projects, invading the jurisdiction of states.[380] Utah Commission argues that the Commission stated its intention in the ANOPR and NOPR to unlawfully influence the generation mix.[381] It claims that Order No. 1920 ''effectively rigs the planning and cost allocation process to ensure (i) FERC's preferred stakeholders' projects are selected in the planning process and (ii) these preferred stakeholders are not required to bear the full costs associated with their choices.'' [382]

2. Commission Determination

135. We appreciate these concerns articulated on rehearing and believe several clarifications that we adopt below will alleviate these concerns. Nonetheless, we sustain the Commission's determination that Order No. 1920 is a valid exercise of our statutory authority under the FPA and does not unlawfully intrude into areas of reserved state authority.[383] In arguing to the contrary, the rehearing requests fail to meaningfully address the substance of Order No. 1920 and fail to respond to the Commission's explanation for why that rule falls within its jurisdiction. Instead, they misconstrue that rule as attempting to control or influence the generation mix in favor of allegedly Commission-preferred resources.[384] Moreover, the arguments on rehearing are unjustified as a legal matter as they fail to apply *EPSA* to Order No. 1920 (and in many cases, do not even acknowledge this controlling precedent).[385] They also depend on the mistaken view that the policies of one state may not have permissible extraterritorial effects on other states through interstate commerce, including in the context of interstate transmission of electricity as regulated under the FPA.[386]

a. Order No. 1920 Does Not Attempt To Control the Generation Mix or Intrude in Areas of State Authority

136. We begin our discussion of the Commission's statutory authority to issue Order No. 1920 with the substance of Order No. 1920. In broad strokes, Order No. 1920 required 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.'' [387] As affirmed by the D.C. Circuit, regional transmission planning and cost allocation processes are practices directly affecting rates subject to the Commission's sole jurisdiction, as transmission providers ''use those processes to 'determine which transmission facilities will more efficiently or cost-effectively meet' transmission needs.'' [388]

137. In light of the direct effects that transmission planning processes have on Commission-jurisdictional rates, ''the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000.'' [389] Order No. 1920 thus does not stand in a vacuum, but rather ''build[s] upon more than a quarter century of significant actions taken by the Commission on transmission planning and cost allocation,'' [390] particularly by addressing specific gaps in the existing regional transmission planning process set forth in Order No. 1000.[391]

138. Order No. 1920 required transmission providers to conduct Long-Term Regional Transmission Planning 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.[392] To identify these Long-Term Transmissions Needs and transmission facilities that meet such needs, transmission providers must develop a set of at least three plausible and diverse Long-Term Scenarios, using the best available data inputs about the future electric power system, over a transmission planning horizon of no less than 20 years.[393] In developing such scenarios, transmission providers

[378] Arizona Commission Rehearing Request at 11–12 (citing *Fed. Power Comm'n* v. *S. Cal. Edison Co.,* 376 U.S. 205, 210 (1964), for the proposition that Congress intended to draw an easily ascertained bright line between state and federal jurisdiction); *id.* at 13; *cf. id.* at 6–7 (arguing that ''nothing in federal jurisprudence or the FPA allows FERC to usurp these traditional state functions of intrastate transmission and balancing such energy source costs with ratepayer fairness'').

[379] Idaho Commission Rehearing Request at 4–5.

[380] Montana Commission Rehearing Request at 2–4 (citing *EPSA,* 577 U.S. at 295–96; *Pac. Gas & Elec. Co.,* 461 U.S. at 212; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56–59; Wyoming Commission Rehearing Request at 2–4 (similar); West Virginia Commission Rehearing Request at 3–4, 10–12 (similar, also arguing that ''[w]ithout a meaningful voluntary state agreement process, the Commission erred by exceeding its jurisdiction and interfering with state decisions about generation resource planning and approval'').

[381] Utah Commission Rehearing Request at 4–5.

[382] *Id.* at 5–6 (arguing that Order No. 1920 ''precludes transmission planners and cost allocation from distinguishing between transmission projects that are necessary to resolve an identified reliability or economic concern from those that are only necessary because some state, local government, or corporation has unilaterally adopted a policy''); *see id.* at 8 (''[T]he FPA gives FERC no authority to regulate electricity generation and specifically reserves that power to the states.'').

[383] Order No. 1920, 187 FERC ¶ 61,068 at PP 253–54.

[384] *See, e.g.,* Undersigned States Rehearing Request at 3–4, 12–13; Designated Retail Regulators Rehearing Request at 11–15; Georgia Commission Rehearing Request at 3–4; Idaho Commission Rehearing Request at 2, 4–5; Alabama Commission Rehearing Request at 5; Arizona Commission Rehearing Request at 2, 11–12, 15; Montana Commission Rehearing Request at 3–4; Wyoming Commission Rehearing Request at 3–4; West Virginia Commission Rehearing Request at 12; Utah Commission Rehearing Request at 1, 3–7.

[385] *See* Designated Retail Regulators Rehearing Request at 3–4, 6, 11–15 (no citation of *EPSA*); Georgia Commission Rehearing Request at 3–4 (same); Idaho Commission Rehearing Request at 2, 4–5 (same); Arizona Commission Rehearing Request at 2, 9–12, 15 (same); Alabama Commission Rehearing Request at 5 (same); Utah Commission Rehearing Request at 1, 3–7; Undersigned States Rehearing Request at 14 (citing *EPSA* as recognizing the steady flow of jurisdictional disputes under the FPA); Montana Commission Rehearing Request at 3 (citing *EPSA* as establishing that ''FERC regulation of jurisdictional subject matters (wholesale sales and transmission) may influence matters within the states' power to regulate''); Wyoming Commission Rehearing Request at 2–3 (same); West Virginia Commission Rehearing Request at 11 (same).

[386] *See, e.g.,* Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 11, 14; Utah Commission Rehearing Request at 12; West Virginia Commission Rehearing Request at 12; *see also infra* Order No. 1920 Does Not Require Unlawful Subsidization of State Policies section.

[387] Order No. 1920, 187 FERC ¶ 61,068 at P 1; *see also id.* PP 224–248.

[388] *Id.* P 86 (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56); *id.* (''[T]hese processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates . . . .'').

[389] *Id.* P 14; *see also id.* PP 15–19 (describing the reforms in Order No. 1000).

[390] *Id.* P 255.

[391] *Id.* P 256; *see also id.* PP 257–259 (describing how Order No. 1920 is consistent with the approach in Order No. 1000, including in that Order No. 1920 does not mandate the development of particular transmission facilities, intrude on siting processes for transmission facilities, or change existing mechanisms for cost recovery); *id.* P 266.

[392] *Id.* P 38; *see also id.* PP 1–13, 225.

[393] *See id.* PP 40, 248.

must consider certain known determinants of transmission needs, which the Commission identified in Order No. 1920 as falling within seven categories of factors that affect Long-Term Transmission Needs.[394]

139. The categories of factors the Commission identified were ''(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; (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.'' [395] The Commission identified these categories of factors because they provide information about the drivers of Long-Term Transmission Needs, including changes in reliability needs, demand, and supply (such as the generation resource mix) that, in turn, affect what transmission facilities will be required going forward.[396] The Commission stated that transmission providers have discretion, however, to consider additional factors [397] and may, in developing their Long-Term Scenarios, find that any factor is not, in fact, likely to affect Long-Term Transmission Needs.[398]

140. Under Order No. 1920, transmission providers must also identify and evaluate transmission facilities to meet such Long-Term Transmission Needs and for potential selection as Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.[399] Here, the Commission required that transmission providers measure and use at least seven specified benefits as part of that analysis,[400] which measurement reflects ''the value that the transmission providers expect a particular Long-Term Regional Transmission Facility to provide to transmission customers in the transmission planning region.'' [401] The Commission provided transmission providers with extensive flexibility in the measurement of such benefits.[402]

141. The Commission also required 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.'' [403] It provided a process for robust participation by Relevant State Entities to seek to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[404] However, the Commission found that ''[w]hile we permit transmission providers to include a State Agreement Process in their OATTs . . . it cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities,'' [405] and required that ''the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop.'' [406]

142. The bases for the reforms in Order No. 1920 are entirely focused on improving Commission-jurisdictional processes. The Commission found that existing transmission planning and cost allocation processes are inadequate, such that ''transmission providers are often not identifying, evaluating, or selecting more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs.'' [407] Trends in ''economics, growing demand, and federal, federally-recognized Tribal, state, and local policies [that] are already resulting in significant changes in the resource mix'' [408] have reinforced that more effective transmission planning ''helps to ensure cost-effective transmission development for customers and can yield better returns for every dollar spent.'' [409] In fact, ''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 rule requires, customers have seen clear and quantifiable benefits.'' [410] In issuing Order No. 1920, the Commission was thus acting in a responsive capacity to account for observable, large-scale, and preexisting trends driven by external forces, which highlighted the need for improved transmission planning and cost allocation processes.[411]

143. As this summary reflects,[412] Order No. 1920 directly regulates transmission planning and cost allocation processes, effectuating one of the ''core objects'' of the FPA, as identified by the Supreme Court: ''ensur[ing] effective transmission of electric power.'' [413] And the parties arguing that Order No. 1920 unlawfully intrudes into reserved areas of state authority do not identify any aspect of Order No. 1920 that is not, on its face, directed toward these Commission-jurisdictional targets.[414] Rather, they argue that Order No. 1920 intrudes on state resource selection because, in regulating such *transmission* planning

[394] *See id.* PP 248, 387–537.

[395] *Id.* P 409. As discussed below, we are setting aside the requirement in Factor Category Seven to consider corporate commitments. *See infra* Requests to Omit One or More Specific Categories of Factors section. That change does not affect our conclusion as to the Commission's statutory authority, including our response to the arguments on rehearing addressing the federal/state division of authority under the FPA.

[396] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 90–111, 299–300, 432, 440, 447, 456, 463, 472, 481.

[397] *See id.* P 412.

[398] *See id.* PP 415, 417.

[399] *See id.* PP 1–3, 40, 225, 719–720.

[400] *See id.* P 3; *see also id.* PP 729, 737.

[401] *Id.* P 269; *see also id.* P 720 (identifying the benefits to be considered).

[402] *See, e.g., id.* PP 728, 735, 839.

[403] *Id.* P 5; *see also id.* P 43 (defining Long-Term Regional Transmission Cost Allocation Method); *id.* P 1291.

[404] *See id.* PP 5, 1291.

[405] *Id.* P 1292; *see id.* P 1293 (explaining that, if transmission providers were to rely solely on a State Agreement Process, this gives rise to the possibility there would be no cost allocation method for Long-Term Regional Transmission Facilities such that selected facilities would be less likely to be developed and their benefits less likely to be realized).

[406] *Id.* P 1292.

[407] *Id.* P 87.

[408] *Id.* P 99 (noting that ''as of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources'' whereas most capacity retirements were from coal resources, with these trends projected to continue); *see also id.* PP 94–98 (discussing trends that shape transmission needs and reflect the need for more efficient and cost-effective transmission planning).

[409] *Id.* P 100 (''Conversely, inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill . . . .''); *see also, e.g., id.* PP 103–06, 121, 123, 236; *cf. id.* P 101 (discussing that existing transmission planning requirements have ''yielded only limited investments in regional transmission projects'').

[410] *Id.* P 102.

[411] *See, e.g., id.* P 129 (''[T]he Commission is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's jurisdiction or control . . . .''); *id.* P 130; *id.* P 261 (''[T]his final rule *responds* to changes in the electric industry that have arisen in the years since the Commission's last regulatory action related to transmission planning.'').

[412] This summary addresses aspects of Order No. 1920 as pertinent to the challenges to the Commission's statutory authority raised on rehearing.

[413] *EPSA,* 577 U.S. at 290; *see also S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 57 (''Reforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities . . . involves a core reason underlying Congress' instruction in Section 206.'').

[414] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 265–66.

and cost allocation, Order No. 1920 is purportedly biased toward the construction of transmission facilities that will serve allegedly Commission-favored resources, which will in turn affect the generation resource mix.[415] Here, they focus on the categories of factors that the Commission identified as reflecting known determinants of transmission needs, arguing that certain of these factors are not resource neutral.[416]

144. The rhetoric in the rehearing requests suggesting that the Commission exceeded its statutory authority by directing reforms targeted at certain transmission planning outcomes demonstrates a misunderstanding of Order No. 1920, and particularly the categories of factors.[417] The Commission found that the categories of factors set forth in Order No. 1920 reflect known determinants of transmission needs,[418] such that requiring that transmission providers consider these factors in Long-Term Regional Transmission Planning is appropriate and reasonable. The substantive content of these factors (for example, a state law or policy implementing the state's reserved authority over resource choices) and how they affect transmission providers' development of Long-Term Scenarios (for example, the extent to which they may lead to the identification of specific Long-Term Transmission Needs) will be attributable to exogenous forces independent of Commission action.[419] Indeed, these forces are drivers of the pre-existing trends, discussed above, that have demonstrated the urgency of more effective transmission planning.[420] In other words, the Commission is not requiring consideration of these factors in order to achieve particular outcomes in the transmission planning process, but rather acting in a responsive capacity to identify and account for the most likely variables that are relevant to effective Long-Term Regional Transmission Planning and ensure that those variables are considered in such planning.[421]

145. Factor Category One (federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand) is illustrative,[422] although these same points also apply to the other categories of factors. Because such laws and regulations, by definition, ''affect[ ] the resource mix and demand'' and, in turn, changes in resource mix and demand can affect Long-Term Transmission Needs,[423] these laws and regulations are relevant to determining such transmission needs. The effect of such laws and regulations on transmission needs is inevitable[424] and would be the same even in the absence of Order No. 1920.[425] Furthermore, the existence and content of such laws and regulations are independent of any Commission action, as they are attributable instead to the lawful exercise of the authority of the entities, including states, responsible for enacting or promulgating such laws and regulations. Order No. 1920 thus requires Long-Term Regional Transmission Planning that *accounts* for the effects of these laws and regulations on transmission needs, because failure to adequately do so has had, and will continue to have, significant deleterious consequences.[426] Order No. 1920 does not create these effects or aim to influence them.

146. Contrary to claims in the rehearing requests,[427] the categories of factors set forth in Order No. 1920 are also resource-neutral. Factor Category One is, again, illustrative. To the extent a law or regulation affects the resource mix or demand, transmission providers must consider how that law or regulation may affect Long-Term Transmission Needs. This requirement applies to all laws and regulations falling within Factor Category One, irrespective of their substantive content.[428] Thus, to the extent a state law may affect the resource mix because, for example, it encourages or discourages the development of *any* particular type of generation, that would be a relevant consideration in Long-Term Regional Transmission Planning.[429] This same point applies to all of the categories of factors specified in Order No. 1920: transmission providers must consider those categories of factors in developing Long-Term Scenarios irrespective of the substantive content of any given factor in a category.

147. In this respect, the categories of factors identified in Order No. 1920 are best understood as a non-exhaustive identification of essential inputs

[415] *See* Undersigned States Rehearing Request at 13; Designated Retail Regulators Rehearing Request at 14; Georgia Commission Rehearing Request at 3–4; Arizona Commission Rehearing Request at 9–12, 15; Idaho Commission Rehearing Request at 4–5; Utah Commission Rehearing Request at 4–5; Montana Commission Rehearing Request at 3–4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 3–4; Alabama Commission Rehearing Request at 5; *cf.* Ohio Commission Federal Advocate Rehearing Request at 18–20 (asserting that, in doing so, the Commission is violating the Commerce Clause of the Constitution).

[416] *See* Undersigned States Rehearing Request at 10–13, 27–28 (arguing that Order No. 1920 and that the categories of factors, in particular, ''are not resource neutral''); Designated Retail Regulators Rehearing Request at 14–15, 26–28 (same); Georgia Commission Rehearing Request at 4; Idaho Commission Rehearing Request at 4–5; Ohio Commission Federal Advocate Rehearing Request at 18–20; Utah Commission Rehearing Request at 4–5; Montana Commission Rehearing Request at 3–4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 3–4.

[417] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 260 (''In this final rule, the Commission neither aims to influence the resource mix, nor, as a practical matter, could the final rule achieve such an outcome.''); *see also id.* PP 129–30, 254, 419; *cf. Dep't of Com.* v. *N.Y.,* 588 U.S. 752, 780–81 (2019) (''A court is ordinarily limited to evaluating the agency's contemporaneous explanation in light of the existing administrative record.''); *Pharm. Rsch. & Mfrs. of Am.* v. *F.T.C.,* 790 F.3d 198, 212 (D.C. Cir. 2015) (noting the presumption of procedural regularity and substantive rationality that attaches to final agency action).

[418] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 119–120, 130, 412, 415; *see also id.* PP 422–84 (discussing the adoption of the specific categories of factors).

[419] *See id.* PP 129–130, 233, 261–62, 419, 436.

[420] *See supra* Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes section.

[421] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 230, 266.

[422] *See id.* P 130 n.328 (citing *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 . . . .''); *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'')).

[423] We note that the arguments on rehearing require recognizing that different types of generating resources, located in different areas, may have different transmission needs. *See, e.g.,* Undersigned States Rehearing Request at 10, 16. In this respect, the rehearing requests tend to reinforce, rather than rebut, that the categories of factors set forth in Order No. 1920 are salient considerations for effective transmission planning.

[424] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 435 (''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.'').

[425] *See id.* P 436 (explaining that ''because . . . 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'').

[426] *See id.* PP 130, 233, 261–262.

[427] *See supra* P 143 n.416.

[428] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 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.'').

[429] Similarly, where a state has laws or regulations that are, themselves, resource neutral or lacks laws or regulations affecting the generation mix or demand, the relevant transmission providers must conduct their Long-Term Regional Transmission Planning considering those considerations.

relevant to Long-Term Regional Transmission Planning. To the extent that, in developing any Long-Term Scenarios, these inputs may point toward identification of particular Long-Term Transmission Needs, this will be the result of external forces that determine the substance of these inputs. In fact, the evaluation of these inputs will be conducted by transmission providers in consultation with relevant stakeholders without the Commission imposing any requirements that dictate the substantive outcome of the transmission planning process.[430] Indeed, all the requirements that the Commission has established for conducting Long-Term Regional Transmission Planning—such as the number of Long-Term Scenarios to be developed, the time horizon to be considered, that scenarios be ''plausible and diverse,'' and that the best available data be used—are also process-focused and resource-neutral.[431]

148. Moreover, the discretion afforded to transmission providers in conducting their analyses further precludes the Commission from attempting to ''put a thumb on the scale'' of the transmission planning process to favor certain generation resources. Transmission providers may consider additional factors, beyond those specified in the categories of factors set forth in Order No. 1920, in developing Long-Term Scenarios and identifying Long-Term Transmission Needs.[432] Transmission providers also ''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).'' [433] Thus, the categories of factors set forth in Order No. 1920 reflect minimum standards that transmission providers may not ignore when developing Long-Term Scenarios. However, as long as these scenarios otherwise meet the requirements of Order No. 1920 (*e.g.,* they are plausible and diverse), Order No. 1920 ensures that transmission providers may consider *all* of the relevant factors and may also determine, in any given case, that any factor is *not* likely to affect such needs. This construct is wholly consistent with resource-neutral transmission planning.[434]

149. Certain rehearing requests state that other aspects of Order No. 1920 (such as the seven required benefits to evaluate Long-Term Regional Transmission Facilities) are preferential toward allegedly Commission-favored resources. These arguments are not well developed.[435] Nonetheless, based on our best understanding of these arguments, we disagree with them for reasons similar to those articulated above and in Order No. 1920. Requiring that transmission providers measure and use, at a minimum, the seven required benefits in evaluating Long-Term Regional Transmission Facilities does not attempt to influence the external forces driving the need for new transmission facilities or displace the authority of other actors. Rather, this requirement helps to ensure that transmission providers conducting Long-Term Regional Transmission Planning have sufficient information to make their decisions, including as to which Long-Term Regional Transmission Facilities will ''more efficiently or cost-effectively address Long-Term Transmission Needs.'' [436] Here, too, the Commission's approach has not been overly prescriptive, as transmission providers may propose on compliance to measure additional benefits as part of Long-Term Regional Transmission Planning [437] and the Commission has afforded transmission providers flexibility as to how to measure each required benefit.[438]

150. Thus, Order No. 1920 reflects a modest exercise of well-established Commission authority. To be sure, there is an urgent and growing need for new transmission infrastructure, driven by a wide variety of factors, including those leading to changes in the generation resource mix.[439] Order No. 1920 identifies those factors, which are occurring independent of Commission action, and gives transmission providers the tools they need to respond to this need and these changes.[440] The parties that argue that the Commission is attempting to influence the generation resource mix by requiring transmission providers to consider these factors to inform their Long-Term Regional Transmission Planning are reversing cause and effect that necessitated the issuance of Order No. 1920.[441]

b. Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority

151. As discussed above, in filling the discrete gaps in the Order No. 1000 regional transmission planning and cost allocation process, the Commission carefully tailored the reforms it adopted to avoid intruding on areas of reserved state authority. But because the spheres of federal and state authority over electricity are not ''hermetically sealed'' from one another,[442] we recognize the possibility that Order No. 1920's requirements—although entirely focused on addressing practices within the Commission's jurisdiction—may have effects on areas of reserved state authority.

152. While the rehearing requests discuss the text of the FPA and precedent reflecting that states have reserved authority in certain areas, including over the selection and approval of generation resources, they fail to discuss key Supreme Court precedent in *EPSA* as it applies Order

[430] We further strengthen those consultation requirements in this order by requiring transmission providers to consult with and consider the positions of Relevant State Entities as to how to account for factors related to state public policies in Long-Term Regional Transmission Planning assumptions.

[431] *See id.* P 248 (summarizing those process-focused requirements).

[432] *See id.* P 412.

[433] *See id.* P 417 (further providing that transmission providers must ''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''); *see also id.* P 415.

[434] Transmission providers also have discretion regarding ''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).'' *Id.* P 417.

[435] *See, e.g.,* Undersigned States Rehearing Request at 3–4, 8, 27–29 (asserting that the ''factors and benefit metrics'' will ''favor some resources over others''; arguing that particular factors are not ''resource neutral'' but no similar argument or explanation as to the benefits metrics); Designated Retail Regulators Rehearing Request at 3–4, 8, 26–29 (similar); Arizona Commission Rehearing Request at 15.

[436] Order No. 1920, 187 FERC ¶ 61,068 at PP 667, 721; *see also id.* P 722 (''[W]ithout 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.''); *id.* P 723.

[437] Order No. 1920, 187 FERC ¶ 61,068 at P 667.

[438] *Id.* P 728; *cf. id.* P 734 (''[W]hile this final rule 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.'').

[439] *See id.* PP 90–99.

[440] *See id.* P 233 (''These changes are occurring independent of any action that we take in this final rule, and they are being driven by a wide variety of factors. This final rule provides transmission providers with the tools that they need to respond to these factors . . . .'').

[441] Claims that the Commission ''advertised'' its ''unlawful purpose'' in the ANOPR and NOPR, *see* Utah Commission Rehearing Request at 4–5, are erroneous for much the same reason: they misconstrue statements in which the Commission discussed the need for transmission reform to respond to changes in the resource mix driven by external factors, including increased penetration of renewable resources, as indicative of an intention to drive such changes.

[442] *EPSA,* 577 U.S. at 281.

No. 1920. Despite the Commission's lengthy discussion of *EPSA* in Order No. 1920, on rehearing we are confronted with no argument that the Commission erred in its analysis or misapplied that decision to the facts here.

153. Under the FPA, the Commission has exclusive jurisdiction over ''the transmission of electric energy in interstate commerce,'' and ''the sale of electric energy at wholesale in interstate commerce.'' [443] The Supreme Court has ''construed broadly'' this grant of jurisdiction over interstate transmission of electricity.[444] Under this grant of authority, ''ensur[ing] effective transmission of electric power'' is one of the ''core objects'' of the FPA.[445] FPA section 206 is one of the principal tools Congress afforded the Commission to exercise this authority, under which it may find that practices affecting Commission-jurisdictional rates are ''unjust, unreasonable, unduly discriminatory or preferential,'' and determine the just and reasonable practice to be thereafter observed and in force.[446] As the D.C. Circuit has recognized, the authority afforded to the Commission under FPA section 206 is ''broadly stated'' and not a ''subtle device.'' [447]

154. The Commission does not, however, have jurisdiction 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,'' except as specifically provided.[448] FPA section 201 also contains a policy statement recognizing the need for Federal regulation in areas subject to the Commission's jurisdiction, but also providing that ''Federal regulation, however, [is] to extend only to those matters which are not subject to regulation by the States.'' [449] Thus, as the rehearing requests point out, courts and the Commission have recognized certain reserved areas of state authority, including over electricity generation.[450]

155. Under *EPSA,* Order No. 1920 is a lawful exercise of the Commission's authority because it regulates practices that directly affect the rates for the transmission of electric energy in interstate commerce—transmission planning and cost allocation processes—and directly regulates only those practices.[451] These findings are not contested in the rehearing requests challenging the Commission's authority. As discussed in Order No. 1920 and above, Order No. 1920 is also not aimed at and does not regulate any area of reserved state authority, whether over electricity generation or otherwise, confirming that the rule is within the Commission's authority.[452] While it would be unlawful for the Commission to regulate within reserved state areas of authority, even as a means of accomplishing objectives within the Commission's statutorily granted authority,[453] a Commission regulation does not run afoul of FPA section 201(b) just because it affects, even substantially, a reserved area of state authority.[454] To the contrary, the rule is exactly the opposite: when the Commission regulates within the areas set forth for its authority in FPA sections 201 and 206 (here, practices directly affecting rates for interstate transmission of electricity) as part of ''carrying out its charge to improve how that market runs . . . [FPA section 201(b)] imposes no bar'' to such regulation, ''no matter the effect'' on areas of state authority.[455] *EPSA* is, therefore, fatal to the arguments asserting that Order No. 1920 is unlawful on the theory that, by regulating transmission planning processes and cost allocation, Order No. 1920 may affect state generation resource planning or other areas of state authority.

156. Furthermore, the rehearing requests disregard how Order No. 1920 ensures that Long-Term Regional Transmission Planning processes facilitate and respect the lawful authority of actors, including states, in areas such as generation resource planning, electricity production, and electricity demand. Factor Categories One, Two, and Three, in particular, require transmission providers to consider ''(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.'' [456] Far from intruding on the authority of states in these domains, Order No. 1920 requires that in

[443] 16 U.S.C. 824(b)(1) (''The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy . . . .'').

[444] *N.Y.* v. *FERC,* 535 U.S. at 15.

[445] *EPSA,* 577 U.S. at 290.

[446] 16 U.S.C. 824e(a).

[447] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56 (''The authority and obligation that Congress vested in the Commission to remedy certain practices is broadly stated and the only question is what limits are fairly implied.''); *see also id.* at 55 (''The text does not define 'practice,' although use of the word 'any' amplifies the breadth of the delegation to the Commission.'').

[448] 16 U.S.C. 824(b)(1).

[449] *Id.* 824(a). This policy statement does not nullify the grant of authority to the Commission in the FPA. *See N.Y.* v. *FERC,* 535 U.S. at 22 (''Moreover, we have described the precise reserved state powers language in [FPA section] 201(a) as a mere policy declaration that cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose.'' (quotation marks omitted)).

[450] *See Pac. Gas & Elec. Co.,* 461 U.S. at 205 (''Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.''); *Monongahela Power Co.,* 40 FERC ¶ 61,256 at 61,861 (''[J]urisdiction over the capacity planning, determination of power needs, plant siting, 1icensing, construction, and the operations of coal-fired plants had been deliberately withheld from our control or responsibility . . . .''); *cf. Nw. Cent. Pipeline Corp.,* 489 U.S. at 522 (''Unless clear damage to federal goals would result, FERC's exercise of its authority [under the Natural Gas Act] must accommodate a State's regulation of production [of natural gas].''); *Piedmont Env't Council,* 558 F.3d at 310 (''The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities.''); *Calpine Corp.* v. *PJM Interconnection,* 171 FERC ¶ 61,035 (Glick, Comm'r, dissenting at P 5).

[451] Order No. 1920, 187 FERC ¶ 61,068 at P 263 (noting that ''no commenter contests'' this point); *see id.* P 265–66; *EPSA,* 577 U.S. at 278 (construing the text of FPA section 206 regarding the Commission's '''affecting' jurisdiction'' as limited to rules or practices that ''directly affect'' the rates within the Commission's jurisdiction); *NARUC,* 964 F.3d at 1186–87 (applying *EPSA,* considering whether the practice at issue meets the ''directly affects'' test, whether the Commission directly regulates state areas of authority, and whether the Commission action does not conflict with the FPA's core purposes); *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 63 (''[B]ecause the orders' 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.''' (citation omitted)); *Conn. Dep't of Pub. Util. Control* v. *FERC,* 569 F.3d at 481–82 (where economic impact of FERC regulation would likely cause States to construct new generation facilities, such state response was not the result of a ''direct regulation'' of generation facilities but the product of a state's response to changed incentives and ''has little relevance'').

[452] *See NARUC,* 964 F.3d at 1186–87 (finding that Commission order did not unlawfully regulate matters left to the States; ''States remain equipped with every tool they possessed prior to Order No. 841 to manage their facilities and systems.'').

[453] *See EPSA,* 577 U.S. at 279–80 (positing a hypothetical in which the Commission ''issued a regulation compelling every consumer to buy a certain amount of electricity on the retail market'' as a means of altering wholesale prices falling with the Commission's jurisdiction and explaining that this would be unlawful ''because it specifies terms of sale at retail—which is a job for the States alone'').

[454] *See id.* at 281 (''[A] FERC regulation does not run afoul of 824(b)'s proscription just because it affects—even substantially—the quantity or terms of retail sales.''); *NARUC,* 964 F.3d at 1186–87; Order No. 1920, 187 FERC ¶ 61,068 at P 264; *see also id.* PP 265–266.

[455] *EPSA,* 577 U.S. at 281–82 (such effects are ''of no legal consequence''); Order No. 1920, 187 FERC ¶ 61,068 at P 264; *see also id.* PP 265–66.

[456] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

developing Long-Term Scenarios transmission providers account for that authority in Long-Term Regional Transmission Planning and, in fact, afford states *maximum* respect for that authority by assuming that these laws, regulations, integrated resource plans, and expected supply obligations will be fully met.[457] If anything, the Commission has adopted a conservative approach to ensure that Order No. 1920 is consistent with the structure of federalism set forth in the FPA.[458]

c. Order No. 1920 Does Not Require Unlawful Subsidization of State Policies

157. We also remain unpersuaded by arguments that Order No. 1920 exceeds the Commission's authority because it will allegedly intrude into state authority by requiring them to effectively subsidize the policies or generation resource mixes of other states.[459] Nothing in Order No. 1920 requires a state to subsidize the policies of other states.[460] In particular, and among other requirements to ensure such subsidization will not occur, Order No. 1920 mandates ''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.'' [461]

158. No cost allocation method proposals have yet been submitted to the Commission in response to Order No. 1920, let alone approved, and application of any such hypothetical Commission-approved proposals to particular Long-Term Regional Transmission Facilities is even further in the future. As a result, disputes about the precise cost allocation method that transmission providers may file, the benefits associated with particular transmission facilities, or how the costs of those particular facilities may be allocated are necessarily theoretical and premature. Regardless, Order No. 1920's bedrock requirement that the cost allocation proposals that will eventually be filed must comply with the beneficiary-pays cost allocation principle is inconsistent with parties' claims that the Commission is unlawfully requiring consumers who do not benefit from Long-Term Regional Transmission Facilities to subsidize such facilities. This beneficiary-pays approach is a just and reasonable basis for allocating costs of regional transmission projects.[462] Indeed, courts and the Commission have explained that requiring that the costs imposed must be at least roughly commensurate to the benefits received [463] ensures that rates remain ''just'' by avoiding subsidization.[464]

159. Furthermore, the requests for rehearing arguing that Order No. 1920 intrudes on their authority by requiring such subsidization place too much weight on the broad premise that states have reserved authority over generation resource planning and electricity production within their own borders.[465] This, however, is a far cry from establishing that state authority over generation within that state's own borders also includes a right to be free from the incidental effects of policies of other states (*e.g.,* as to generation planning) as those effects may manifest through interstate commerce in electricity. For example, Undersigned States and Designated Retail Regulators cite the federal/state division of authority set forth in the FPA, and argue that ''[e]ach state has authority over the choice of which generating resources are maintained and constructed within its own jurisdiction.'' [466] However, they then recast this as a broader ''right to choose the resources that best fit their public policies,'' a framing that omits the geographic limitation that states' reserved authority over such resources applies only to resources within their

[457] *See id.* PP 417, 507. At the same time, the Commission in Order No. 1920 reasonably recognized that the first three categories of factors are not the only known determinants of transmission needs.

[458] FPA section 215(i)(3), 16 U.S.C. 824o(i)(3), and section 216, 16 U.S.C. 824p, which certain rehearing requests cite in passing, *see* Undersigned States Rehearing Request at 6, 11; Designated Retail Regulators Rehearing Request at 6–7, 13, 18–19, do not affect this conclusion. Neither provision limits the Commission's authority over transmission planning processes or cost allocation under the FPA. Rather, section 215(i)(3) establishes that ''[n]othing in this section,'' relating to establishment of Electric Reliability Organizations, ''shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard.'' The National Interest Electric Transmission Corridor process in section 216 affords the Commission, in certain circumstances, authority over siting of interstate electric transmission facilities; the siting of particular transmission facilities is not at issue in Order No. 1920. *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 254, 258.

[459] *See* Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 14–15; Georgia Commission Rehearing Request at 5–6; Arizona Commission Rehearing Request at 11–12; Montana Commission Rehearing Request at 2–4; West Virginia Commission Rehearing Request at 2–4, 10–12.

[460] Order No. 1920, 187 FERC ¶ 61,068 at P 267; *see also, e.g., id.* PP 232, 268–70, 280; *cf. id.* P 1419 (''[W]e 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.'').

[461] *Id.* P 267; *see id.* P 268 (discussing various requirements in Order No. 1920, including the beneficiary-pays cost allocation principle, that ''provide robust assurance that the cost allocation methods ultimately proposed under the final rule will not result in improper cost subsidization.''); *id.* P 280.

[462] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 84; *see id.* at 85 (noting that the court had ''repeatedly embraced'' the ''basic tenet'' of beneficiary-pays cost allocation as a logical extension of the cost causation principle and that the Commission has ''reasonably identified the lack of beneficiary-based cost allocation as a practice likely to result in rates that are not just and reasonable or are unduly discriminatory or preferential'' (citing Order No. 1000, 136 FERC ¶ 61,051 at P 487)); *Neb. Pub. Power Dist.* v. *FERC,* 957 F.3d 932, 941 (8th Cir. 2020) (''[I]t is certain that 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. Because NPPD has greatly benefitted from Tri-State's facilities, it is likely that some of the costs have been caused by NPPD.'' (internal quotations and alterations omitted)); *ICC* v. *FERC I,* 576 F.3d at 476 (''Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. 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 . . . .'' (citations omitted)).

[463] As discussed in greater detail below, Order No. 1920 recognized that Long-Term Regional Transmission Facilities are likely to provide a diverse array of benefits. The Commission specifically required that transmission providers consider seven economic and reliability benefits in Long-Term Regional Transmission Planning, but did not prohibit them from also considering public policy benefits. *See infra* Omission of Regional Cost Allocation Principle No. 6 and Ability to Allocate Costs by Type of Project section (reiterating the fundamental principle that costs will be allocated in a manner that is at least roughly commensurate with estimated benefits, ensuring that ratepayers will not pay for facilities from which they do not benefit).

[464] *El Paso Elec. Co.* v. *FERC,* 76 F.4th 352, 361–63 (5th Cir. 2023) (''The cost-causation principle, as understood by the courts and articulated in Order No. 1000, . . . ensure[s] that rates are 'just' . . . [by] prevent[ing] 'subsidization by ensuring that costs and benefits correspond to each other.''' (quoting Order No. 1000–A, 139 FERC ¶ 61,132 at P 578; citing *BNP Paribas Energy Trading GP* v. *FERC,* 743 F.3d at 268; *Nat'l Ass'n of Reg. Util. Comm'rs* v. *FERC,* 475 F.3d 1277, 1285 (D.C. Cir. 2007))).

[465] *See, e.g.,* Undersigned States Rehearing Request at 10–13; Designated Retail Regulators Rehearing Request at 11–14; Montana Commission Rehearing Request at 2–4 (arguing that Order No. 1920 intrudes on state authority because ''without a voluntary state agreement process, the Final Rule's regional cost allocation scheme ensures that nonconsenting states will be swept up in their neighbors' preferred policy projects''); Wyoming Commission Rehearing Request at 2–4 (similar); West Virginia Commission Rehearing Request at 3–4, 10–12 (similar); Arizona Commission Rehearing Request at 13 (''[S]tates without renewable resource policy objectives will be forced to absorb costs generated by the transmission of (often rurally sited) renewable energy.'' (emphasis omitted)); Georgia Commission Rehearing Request at 5–6; Utah Commission Rehearing Request at 6–7.

[466] Undersigned States Rehearing Request at 11–12; Designated Retail Regulators Rehearing Request at 13.

own jurisdiction.[467] As a consequence, they claim, it is ''an over-reach into the traditional area of regulation reserved for the States'' for their residents ''to pay for infrastructure to support[ ] the public policies and resource mixes of other States, without demonstrable benefits to that load'' as the costs of those policies manifest in interstate transmission facility cost allocations.[468]

160. Neither statutory text in the FPA nor any of the precedent cited by the rehearing requests establishes that states' authority, when they participate in interstate commerce in electricity, includes a right to be free from the incidental extraterritorial effects of the policies of other states as they may manifest through such interstate commerce.[469] To the contrary, as the Supreme Court has recognized, ''the production and transmission of energy is an activity particularly likely to affect more than one State.'' [470] The FPA is a congressional enactment authorizing the Commission to regulate in this area.[471]

161. In fact, the FPA was enacted in response to a Supreme Court decision holding that the Commerce Clause prevents states from regulating certain transactions between electric utilities located in other states—thereby creating the ''*Attleboro* gap.'' [472] Congress responded by passing the FPA,[473] preventing the ''creation of any regulatory 'no man's land.' Some entity must have jurisdiction to regulate each and every practice that takes place in the electricity markets.'' [474] *Attleboro* and Congress's enactment of the FPA thus reflect the authority vested in the Commission to regulate in these domains precisely because states are constitutionally incapable of doing so, including as to how the interaction of state policies may manifest in interstate commerce.[475] Moreover, the purported requirement that states must voluntarily agree to any cost allocation for interstate transmission facilities would run the risk of creating the sort of ''regulatory void'' that the FPA was designed to preclude. In particular, it would effectively assign to the states the regulatory responsibility for cost allocation of interstate transmission facilities (notwithstanding that this falls within an area Congress assigned to the Commission in the FPA), creating the possibility that this area goes entirely unregulated should states fail to reach agreement.[476] In other words, far from prohibiting any extraterritorial effects, the FPA's statutory standard puts the Commission in charge of regulating those effects pursuant to the just and reasonable standard, which includes the cost causation principle.

162. The argument that, particularly absent state agreement to cost allocation, Order No. 1920 exceeds the Commission's authority is also ahistorical when viewed in the regulatory context.[477] In Order No. 1000, the Commission required that transmission providers ''devise methods for allocating the costs of certain new transmission facilities to those entities that benefit from them.'' [478] The D.C. Circuit held that this requirement fell within the Commission's statutory authority to regulate practices affecting rates [479] and otherwise rejected challenges to the Commission's authority to adopt these cost allocation reforms under FPA section 206.[480] In addition, Order No. 1000 also adopted Cost Allocation Principle 1, requiring (like Order No. 1920) that the cost of transmission facilities be allocated to those that will benefit from those facilities in a manner at least roughly commensurate with the estimated benefits of that facility.[481] In doing so, the Commission neither required state agreement to *ex ante* cost allocation methods, nor that any such method ensure that costs be allocated based on whether a state agreed with the public policies of other states associated with the generating facilities connected to the relevant transmission facilities.[482] Order No. 1920's approach of requiring an Engagement Period directed toward state agreement on cost allocation, with an *ex ante* cost allocation backstop,[483] thus reflects an expansion of states' ability to participate in the development of regional cost allocation methods as compared to the status quo ante, while recognizing the bounds of state authority. And we take further steps in this order to ensure that states have a meaningful opportunity to inform both Long-Term Regional Transmission Planning and cost allocation for Long-Term Regional Transmission Facilities, particularly with respect to the

[467] Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 14.

[468] Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 14. This reference to ''demonstrable benefits to load'' appears to reflect the view that certain states may disagree with the choices of other states in terms of generation resource selection, particularly on the basis that ''less-remote resources of any type might be less expensive, more reliable, and environmentally beneficial.'' Undersigned States Rehearing Request at 4–5; Designated Retail Regulators Rehearing Request at 4–5 (similar).

[469] No such generic right to avoid the extraterritorial effects of the policies of other states as they may manifest through interstate commerce exists under the Constitution. *See Nat'l Pork Producers Council* v. *Ross,* 598 U.S. 356, 371–74 (2023) (rejecting arguments, under the dormant Commerce Clause, ''invoking . . . an 'almost per se' rule forbidding enforcement of state laws that have the 'practical effect of controlling commerce outside the State,' even when those laws do not purposely discriminate against out-of-state economic interests'').

[470] *Ark. Elec. Co-op. Corp.* v. *Ark. Pub. Serv. Comm'n,* 461 U.S. 375, 377 (1983) (explaining also that the effect of such production and transmission ''on interstate commerce is often significant enough that uncontrolled regulation by the States can patently interfere with broader national interests''); *see* Order No. 1920, 187 FERC ¶ 61,068 at P 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.'').

[471] *See* 16 U.S.C. 824(a), (b)(1), 824d, 824e.

[472] *EPSA,* 577 U.S. at 266 (citing *Pub. Util. Comm'n of R.I.* v. *Attleboro Steam & Elec. Co.,* 273 U.S. 83, 89–90 (1927)).

[473] *Id.*

[474] *Id.* at 289 (citation omitted).

[475] *See Appalachian Power Co.* v. *Pub. Serv. Comm'n of W. Va.,* 812 F.2d 898, 905 (4th Cir. 1987) (enactment of the FPA reflects ''the judgment embodied in the commerce clause that there are situations in which the broader perspective of federal authority is necessary''); *cf. id.* at 904 (''[S]tates are powerless to exert authority that potentially conflicts with FERC determinations regarding rates or agreements affecting rates.'').

[476] Order No. 1920, 187 FERC ¶ 61,068 at P 1293 (''[I]f 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.''); *see also infra* Obligation to File an Ex Ante Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section.

[477] The Supreme Court has observed that ''[i]n our interconnected national marketplace, many (maybe most) state laws have the 'practical effect of controlling' extraterritorial behavior'' such that application of an ''extraterritoriality doctrine'' to preclude such effects would lead to ''strange places.'' *Nat'l Pork Producers Council,* 598 U.S. at 374–75 (citing examples and concluding that adopting this rule would ''cast a shadow over laws long understood to represent valid exercises of the States' constitutionally reserved powers''); *id.* at 390 (noting that the Supreme Court has ''recognized since *Gibbons* [v. *Ogden*], 9 Wheat 1, 22 U.S. 1 (1824), that virtually all state laws create ripple effects beyond their borders'').

[478] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 81; *see id.* at 82–83 (discussing these reforms in more detail).

[479] *See id.* at 84.

[480] *See id.* at 84–87.

[481] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 622; *see S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 85 (''The Commission therefore reasonably identified the lack of beneficiary-based cost allocation as a practice likely to result in rates that are not just and reasonable or are unduly discriminatory or preferential.'' (citing Order No. 1000, 136 FERC ¶ 61,051 at P 487)).

[482] *Cf.* Order No. 1000, 136 FERC ¶ 61,051 at P 685 (permitting, but not requiring, transmission providers to use different types of cost allocation methods for different types of transmission facilities, ''such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements'').

[483] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1291–1292.

implementation and effect of state public policies.

163. Order No. 1920 regulates within, and only within, Commission authority, while ensuring that state policy choices in areas of reserved state authority are respected and effectuated. Order No. 1920 treats such choices evenhandedly and as antecedent to Long-Term Regional Transmission Planning, requiring transmission providers to consider those choices, among other factors, when they identify Long-Term Transmission Needs and (ultimately) Long-Term Regional Transmission Facilities.[484] Long-Term Regional Transmission Planning is, in turn, focused on evaluating the Long-Term Regional Transmission Facilities that will reliably and cost-effectively deliver the power needed to serve the load that is expected given these (and other) drivers of transmission needs.[485] As to cost allocation, transmission providers have flexibility to propose specific cost allocation methods for Long-Term Regional Transmission Facilities, but the prospect of unlawful subsidization of such a transmission facility by customers that do not benefit from it is foreclosed by the requirement that any such method must conform to the beneficiary-pays cost allocation requirement.[486] To be clear, that means that no state or its customers will be required to pay for the costs of Long-Term Regional Transmission Facilities unless they benefit from those transmission facilities and in a manner that is at least roughly commensurate with those costs. This approach toward the interplay of federal and state regulation of electricity wholly comports with the jurisdictional lines drawn in the FPA.[487]

164. Contrast this with the rehearing requests challenging the Commission's authority under the FPA. By virtue of states' connection to the interstate transmission grid, consumers in those states participate in interstate commerce. However, certain parties seeking rehearing object to the potential consequences of that connection, particularly the amount that these ratepayers may be required to pay for the transmission facilities connecting to those resources. But where a ratepayer in one state benefits from a transmission facility, it is appropriate that they bear costs at least roughly commensurate with that benefit.[488]

165. For the reasons stated above and in Order No. 1920, we disagree with arguments that, under the FPA, the Commission's authority to regulate interstate transmission planning processes and cost allocation is limited as these rehearing requests claim. We find that the requirements of Order No. 1920 are within our authority over the ''transmission of electric energy in interstate commerce,'' and particularly to ensure that practices affecting rates for such transmission are just and reasonable.[489]

C. Major Questions Doctrine

1. Requests for Rehearing

166. Several of the rehearing requests also invoke the ''major questions'' doctrine, particularly the Supreme Court's decision in *West Virginia* v. *EPA*,[490] in connection with their contention that Order No. 1920 exceeds the Commission's statutory authority.[491] Undersigned States and Designated Retail Regulators argue that Order No. 1920 involves a ''major question'' such that Order No. 1920 must be supported by clear congressional authorization because the Commission is attempting to supplant state generation planning authority in favor of promoting distantly located renewable energy.[492] They assert that *West Virginia* supports concluding that Order No. 1920 implicates the major questions doctrine.[493] Undersigned States and Designated Retail Regulators also point to the claimed economic consequences of Order No. 1920, citing alleged costs in the hundreds of billions or trillions of dollars; the breadth of the transmission grid; and the importance of electricity in everyday life.[494] They argue that Order No. 1920 is ''blatantly preferential,'' will not ensure just and reasonable rates, and that attempting to influence the generation resource mix exceeds both the Commission's expertise and the scope of the FPA as a consumer-protection statute geared toward ensuring such just and reasonable rates.[495]

167. Likewise, Arizona Commission argues that the Commission has ''implemented a nationwide scheme, foisted on all 50 states, to adopt energy generation modes to *its* liking'' even though ''nothing in th[e FPA] authorizes the adoption of the Biden Administration's renewable energy policy goals.'' [496] Arizona Commission and Utah Commission assert that in *West Virginia* the Supreme Court stated that it is highly unlikely that Congress would leave to agency discretion how much coal-based generation there should be over the coming decades, and assert that major policy changes must occur pursuant to an express statement of Congress.[497] Arizona Commission argues that commenters have observed the breadth and consequences of Order

[484] *See supra* Requests to Omit One or More Categories of Factors section.

[485] *Id.; see also supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

[486] Similarly, we find that Undersigned States and Designated Retail Regulators assertion that they may be required to pay for infrastructure ''without demonstrable benefits to that load,'' Undersigned States Rehearing Request at 12–13; Designated Retail Regulators Rehearing Request at 14, is misplaced. Under the beneficiary-pays principle, costs are assigned to customers only to the extent that they receive demonstrable benefits that are at least roughly commensurate with those costs.

[487] *See EPSA,* 577 U.S. at 282 (''considering 'the *target* at which a law *aims*''' in deciding whether FERC's wholesale market rule fell within its power to regulate wholesale sales (quoting *Oneok, Inc.* v. *Learjet, Inc.,* 575 U.S. 373, 385 (2015)); *cf. Hughes* v. *Talen Energy Mktg., LLC,* 578 U.S. 150, 165 (2016) (holding that states may not set retail rates, a power typically falling on the states' side of the FPA's jurisdictional line, 16 U.S.C. 824(b)(1), in a way that fails to ''give effect'' to a wholesale rate); *Oneok,* 575 U.S. at 385–86 (contrasting a state policy properly aimed at its field of jurisdiction with one aimed directly at the federal field).

[488] Indeed, a contrary rule would arguably be inconsistent with judicial precedent governing cost causation. *See, e.g., El Paso Elec. Co.,* 76 F.4th at 360–63 (finding that the Commission impermissibly ''prohibited the WestConnect region from imposing binding cost allocation on the non-jurisdictional utilities although they will 'cause,' in part, the costs of new grid improvements''); *id.* at 361–62 (explaining that it was of fundamental legal importance that the non-jurisdictional utilities at issue were specifically and intentionally designated as beneficiaries, rather than incidental, unintended beneficiaries, such that they were impermissible ''free riders'' if not allocated an appropriate share of costs).

[489] 16 U.S.C. 824(b)(1), 824d(a), 824e(a).

[490] 597 U.S. 697.

[491] *See* Undersigned States Rehearing Request at 7, 14–17; Designated Retail Regulators Rehearing Request at 7, 15–19; Arizona Commission Rehearing Request at 2, 3–6 & n.8; Idaho Commission Rehearing Request at 2, 6–7; Utah Commission Rehearing Request at 1, 7–8; Ohio Commission Federal Advocate Rehearing Request at 20.

[492] Undersigned States Rehearing Request at 14–15; Designated Retail Regulators Rehearing Request at 15–16; *see also id.* at 17–18 (''[T]here is no clear delegated authority allowing FERC to determine what type of generating resources should be transmitted from where in the United States.'').

[493] Undersigned States Rehearing Request at 14–15 (also asserting that this is a major question because ''it implicates a unique and complex jurisdictional divide between state and federal regulatory authority'' (citing *Ala. Ass'n of Realtors* v. *HHS,* 594 U.S. 758, 764 (2021); *EPSA,* 577 U.S. at 264–65)); Designated Retail Regulators Rehearing Request at 17.

[494] Undersigned States Rehearing Request at 15; Designated Retail Regulators Rehearing Request at 16–17.

[495] Undersigned States Rehearing Request at 16–17; Designated Retail Regulators Rehearing Request at 16–17, 18–19.

[496] Arizona Commission Rehearing Request at 4–6.

[497] *Id.* at 5–6; *see also id.* at 3–4 (arguing that Congress does not use oblique or elliptical language to empower fundamental changes to a statutory scheme); Utah Commission Rehearing Request at 7–8.

No. 1920 [498] and cites a characterization of the Commission's approach as controversial,[499] asserts that the FPA is a consumer protection statute,[500] and states that Congress has not enacted the ''Green New Deal.'' [501] Utah Commission contends that ''transitioning the grid away from fossil-fueled generation and toward renewable resources'' is a major question, pointing to its social and political context and economic consequences.[502]

168. In arguing that Order No. 1920 involves a major question, Idaho Commission points to statements in the concurrence to Order No. 1920 that the nation's energy grid is at a crossroads, with '' 'consequential action' . . . emphatically warranted'' and ''proselytiz[ing] for states to join it in building an 'electric transmission grid for the 21st century.' '' [503] It contends that the Commission has ''gone to great lengths to enact a sweeping policy agenda, in the absence of congressional authority, that infringes on states' authority, and impermissibly attempts to expand the Commission's jurisdiction under the FPA, in violation of the major questions doctrine.'' [504]

169. Ohio Commission Federal Advocate argues, citing *West Virginia,* that the Commission has not identified a clear congressional authorization to ''use its power under the FPA to facilitate federal, state, Tribal, local, and corporate policies, including decarbonization and electrification policies, under the guise of building a robust transmission system.'' [505] It argues that the Commission lacks this authority.[506]

170. SERTP Sponsors bring several requests for clarification of Order No. 1920, which we summarize and address in detail below. Focusing on the ''respect afforded to state-approved IRPs and LSE supply obligations,'' SERTP Sponsors state that, absent certain of those clarifications, ''particularly [in] Sections II.A.1 and II.C.3'' of their argument, Order No. 1920 could encroach on state jurisdiction.[507] They particularly contend that if these clarifications are not granted ''Order No. 1920 would be seeking to influence the makeup of the nation's energy policy and generation mix, which would constitute a 'major question,' given the vast economic consequences that would result from an exercise of such authority.'' [508]

2. Commission Determination

171. We continue to find that Order No. 1920 does not implicate the major questions doctrine. As the summary above reflects, the rehearing requests provide little to no discussion of the scope of the Commission's authority under the FPA or the statutory context and, as discussed in the preceding sections, they misinterpret Order No. 1920 itself.[509] The Supreme Court has described the major questions doctrine as applicable only in ''extraordinary cases,'' which it has identified through a detailed analysis of the statutory context and agency action at issue.[510] Specifically, that doctrine comes into play where, despite a ''colorable textual basis'' for the agency's claim of authority, the agency action was so extravagant when viewed in light of the statutory context that it was unlikely that Congress would have afforded this claimed authority to the agency, and particularly would not have done so in an oblique or subtle way.[511] As a rule, Congress does not ''hide 'elephants in mouseholes.' '' [512]

172. In *West Virginia,* the Supreme Court held that EPA claimed a ''newfound,'' ''transformative,'' ''extravagant,'' and ''unheralded'' [513] authority to ''substantially restructure the American energy market'' by devising emission limitations that were based on EPA's judgment of how much coal-fired electricity generation should be in the overall mix of electricity generation.[514] The Supreme Court concluded that this authority swept far beyond the ordinary understanding of EPA's purview, inserting the agency into areas into which it lacked technical expertise and in which it was required to make ''a very different kind of policy judgment.'' [515] EPA did so against the backdrop of the significant policy questions involved that would ordinarily be addressed by Congress.[516] In fact, the Supreme Court recognized that EPA's newly claimed authority

[498] *See* Arizona Commission Rehearing Request at 6; *cf. id.* at 16 (citing the cost of achieving net-zero on the transmission grid).

[499] *See id.* at 4–5.

[500] *See id.* at 20.

[501] *See id.* at 5.

[502] Utah Commission Rehearing Request at 8 & n.17 (arguing that Order No. 1920 ''patently dictates outcomes and cost allocation and does so to discriminate and favor the policy preferences of certain preferred stakeholders''; citing Commissioner Christie's dissent claiming that Order No. 1920 is intended to cost consumers trillions of dollars).

[503] Idaho Commission Rehearing Request at 6 (quoting Order No. 1920, 187 FERC ¶ 61,068 (Phillips & Clements Comm'rs, concurring at PP 34–35)).

[504] *Id.* at 6–7.

[505] Ohio Commission Federal Advocate Rehearing Request at 20.

[506] *Id.*

[507] SERTP Sponsors Rehearing Request at 37–41; *see also id.* at 41–45.

[508] *Id.* at 39–40 (arguing that ''the application or implementation of Order No. 1920 in a manner that would undercut or conflict with state-regulated IRPs and resource adequacy decisions would transform the regulatory paradigm from an electric system expansion process driven by state-regulated resource assumptions made in state-regulated IRPs to one driven by FERC-regulated resource assumptions made in the FERC-regulated LTRTP processes,'' exceeding the scope of the Commission's expertise and previous regulation of ''practices affecting rates'').

[509] *See supra* Federal/State Division of Authority section.

[510] *See West Virginia,* 597 U.S. at 721.

[511] *Id.* at 722–23; *see also id.* at 721.

[512] *See id.* at 746 (Gorsuch, J., concurring) (quoting *Whitman* v. *Am. Trucking Ass'ns,* 531 U.S. 457, 468 (2001)); *see also Nat'l Fed'n of Indep. Bus.* v. *Dep't of Lab., Occupational Safety & Health Admin.,* 595 U.S. 109, 125 (2022) (Gorsuch, J., concurring).

[513] *West Virginia,* 597 U.S. at 724; *see also Util. Air Regul. Grp.* v. *EPA,* 573 U.S. 302, 323–24 (2014) (*UARG*) (rejecting EPA's ''enormous and transformative expansion in EPA's regulatory authority'' in ''discover[ing] in a long-extant statute an unheralded power'' to require certain permits for greenhouse gas emissions).

[514] *West Virginia,* 597 U.S. at 721, 724–25; *see also Nat'l Fed'n of Indep. Bus.,* 595 U.S. at 117 (''The Secretary has ordered 84 million Americans to either obtain a COVID–19 vaccine or undergo weekly medical testing at their own expense. This is no everyday exercise of federal power.'' (citation omitted)); *UARG,* 573 U.S. at 321–22 (explaining that EPA itself acknowledged the ''calamitous consequences of interpreting the [Clean Air] Act in that way,'' thereby rendering the relevant provisions multiple orders of magnitude more burdensome and expensive); *id.* at 324 (''[W]e confront a singular situation: an agency laying claim to extravagant statutory power over the national economy while at the same time strenuously asserting that the authority claimed would render the statute 'unrecognizable to the Congress that designed' it.'' (citation omitted)); *Food & Drug Admin.* v. *Brown & Williamson Tobacco Corp.,* 529 U.S. 120, 159–60 (2000) (explaining that ''[t]his is hardly an ordinary case'' given that the FDA was now purporting to have authority that would allow it to outright ban tobacco products, notwithstanding the unique place such products have in American history and the existing regulatory scheme adopted by Congress).

[515] *West Virginia,* 597 U.S. at 728–29 (noting that, in this context, EPA was required to make judgments as to the reliability of the energy grid and the effects of its action on energy prices, such that EPA's exercise of authority required ''technical and policy expertise *not* traditionally needed in EPA regulatory development'' (quotation marks omitted)); *see also Nat'l Fed'n of Indep. Bus.,* 595 U.S. at 118 (''[N]o provision of the Act addresses public health more generally, which falls outside of OSHA's sphere of expertise.''); *King* v. *Burwell,* 576 U.S. 473, 485–86 (2015) (declining to defer to the Internal Revenue Service (IRS) interpretation of the Affordable Care Act's guarantee of tax credits for health insurance purchases, noting that that decisions about ''health insurance policy'' fell beyond the IRS's zone of ''expertise,'' making it ''especially unlikely that Congress would have delegated th[e] decision'' over tax credits ''to the *IRS.*'').

[516] *West Virginia,* 597 U.S. at 729–30; *see also King,* 576 U.S. at 485–86 (noting that the tax credits at issue ''involv[e] billions of dollars in spending each year and affect[ ] the price of health insurance for millions of people,'' the Court deemed their provision ''a question of deep economic and political significance'' that Congress would not have implicitly delegated to the agency (quotation marks omitted)).

enabled it to enact a program addressing the dangers posed by greenhouse gas emissions even though Congress had considered (but rejected) legislative proposals to create such programs.[517] Thus, in *West Virginia,* the Supreme Court confronted an EPA assertion of authority that it concluded was elephantine—surprising not just in scope, but also in character vis-à-vis EPA's ordinary regulatory role.

173. The Supreme Court concluded that EPA purported to find that authority in a statutory mousehole: the ''ancillary,'' ''backwater,'' ''gap-filler'' authority in section 111(d) of the Clean Air Act, under which it was to identify the ''best system of emission reduction'' for existing stationary sources of air pollutants.[518] Reflecting the ancillary nature of this provision, the Supreme Court noted that EPA had only used it a handful of times over more than four decades,[519] and in doing so had uniformly based its regulatory approach on identifying systems that would reduce pollution by causing the regulated source to operate more cleanly.[520] As a result, according to the Supreme Court, EPA's claim that it had authority to base emission limitations on its policy judgment regarding the appropriate generation resource mix ''was not only unprecedented; it also effected a fundamental revision of the statute, changing it from [one sort of] scheme of . . . regulation into an entirely different kind.'' [521] The Supreme Court held that, to justify this power, EPA offered only a ''vague statutory grant'' supported by such an expansive, acontextual reading of the ''definitional possibilities'' of the word ''system'' that accepting this construction would have rendered the statutory text an ''empty vessel.'' [522]

174. *West Virginia* thus reflects the sort of ''extraordinary case'' meriting application of the major questions doctrine and illustrating the factors relevant to that inquiry. Moreover, *West Virginia* and other cases in this area reflect that application of that doctrine does not boil down to a facile examination, divorced from the statutory context, of the agency action at issue. The major questions doctrine does not provide, for example, that courts should find that an agency action requires express Congressional authorization based simply on the economic consequences of that action, the fact that the agency is addressing a significant problem, or the sector of industry that the agency is regulating. As the Fourth Circuit recently explained, while the ''doctrine applies only when the question at issue—*i.e.,* the authority the agency is claimed to have—is a major one,'' that is a necessary, not a sufficient, condition triggering the doctrine's application.[523] ''The [Supreme] Court has highlighted several other [relevant] hallmarks,'' such as (1) whether the statute's ''structure indicates that Congress did not mean to regulate the issue in the way claimed,'' [524] (2) whether a '''distinct regulatory scheme' [is] already in place to deal with the issue which would conflict with the agency's newly asserted authority,'' [525] (3) where the agency has ''fail[ed] to invoke the[ ] [asserted powers] previously,'' (4) where the ''asserted authority falls outside the agency's traditional expertise,'' and (5) where the ''asserted authority . . . is found in an 'ancillary provision.' '' [526] As discussed below, none of these ''hallmarks'' is present here.

175. We continue to conclude that the major questions doctrine does not apply to Order No. 1920.[527] The Commission's authority under FPA section 206 is no statutory ''mousehole.'' Far from being an ''ancillary,'' ''back-water,'' or ''gap-filler'' provision as the court referenced in *West Virginia,* FPA section 206 sets forth core Commission regulatory authority to remedy unjust and unreasonable rates, and practices affecting rates, for the transmission of electric energy in interstate commerce.[528] As discussed above, the Commission's action in Order No. 1920 falls well within the ordinary understanding of its statutory authority under this provision, as it is regulating practices directly affecting such rates,[529] such that Order No. 1920 does not involve converting the authority set forth to regulate such practices into a new kind of regulatory scheme.[530] By the same token, since it is based on this core statutory authority, Order No. 1920 also does not involve invoking definitional possibilities to stretch a statutory term or phrase (*e.g.,* ''system''

[517] *West Virginia,* 597 U.S. at 731–32 (''Congress, however, has consistently rejected proposals to amend the Clean Air Act to create such a program.''); *see also Brown & Williamson,* 529 U.S. at 160 (adopting FDA's statutory interpretation required ignoring ''the plain implication of Congress' subsequent tobacco-specific legislation''); *id.* at 142–58.

[518] *West Virginia,* 597 U.S. at 709–710 (noting that the ''thrust of Section 111 focuses on emissions limits for *new* and *modified* sources'' rather than the existing sources that EPA was regulating under the challenged rule); *id.* at 730.

[519] *Id.* at 710–11 (''It was thus only a slight overstatement for one of the architects of the 1990 amendments to the Clean Air Act to refer to Section 111(d) as an 'obscure, never-used section of the law.' '' (citation omitted)).

[520] *Id.* at 725–26 (citing EPA's view, in its inaugural rulemaking under this provision, that Congress in this provision intended a technology-based approach); *see also Nat'l Fed'n of Indep. Bus.,* 595 U.S. at 118–19 (''It is telling that OSHA, in its half century of existence, has never before adopted a broad public health regulation of this kind . . . . [A] vaccine mandate is strikingly unlike the workplace regulations that OSHA has typically imposed.''); *Brown & Williamson,* 529 U.S. at 144 (noting FDA's ''consistent and repeated statements'' that it lacked jurisdiction to regulate tobacco products).

[521] *West Virginia,* 597 U.S. at 728 (quotation marks omitted); *see also Nat'l Fed'n of Indep. Bus.,* 595 U.S. at 117–18 (''The Act empowers the Secretary to set workplace safety standards, not broad public health measures.''); *UARG,* 573 U.S. at 322 (explaining that EPA itself recognized that the results of its statutory interpretation ''would be so 'contrary to congressional intent,' and would so 'severely undermine what Congress sought to accomplish,' that they necessitated as much as a 1,000–fold increase in the permitting thresholds set forth in the statute''); *id.* at 322–23 (explaining how a ''brief review of the relevant statutory provisions leaves no doubt that the PSD program and Title V are designed to apply to, and cannot rationally be extended beyond, a relative handful of large sources capable of shouldering heavy substantive and procedural burdens''); *MCI Telecomms. Corp.* v. *Am. Tel. & Telegraph Co.,* 512 U.S. 218, 234 (1994) (''[FCC's statutory interpretation] is effectively the introduction of a whole new regime of regulation (or of free-market competition), which may well be a better regime but is not the one that Congress established.''); *cf. Brown & Williamson,* 529 U.S. at 156 (''Under these circumstances, it is clear that Congress' tobacco-specific legislation has effectively ratified the FDA's previous position that it lacks jurisdiction to regulate tobacco.'').

[522] *West Virginia,* 597 U.S. at 732; *see also Brown & Williamson,* 529 U.S. at 160 (explaining that FDA's statutory interpretation required adopting ''an extremely strained understanding of 'safety' as it is used throughout the Act'' even though the concept is ''central to the [Act's] regulatory scheme''); *MCI,* 512 U.S. at 229–34 (rejecting agency interpretation concluding that a statutory provision authorizing the FCC to ''modify'' the provisions of 47 U.S.C. 203 authorized the agency to make ''radical or fundamental changes to the statutory requirements'').

[523] *N.C. Coastal Fisheries Reform Grp.* v. *Capt. Gaston LLC,* 76 F.4th 291, 296–97 (4th Cir. 2023).

[524] *Id.*

[525] *Id.* (quoting *Brown & Williamson,* 529 U.S. at 143–46).

[526] *Id.* (quoting *Whitman* v. *Am. Trucking Ass'ns, Inc.,* 531 U.S. at 468).

[527] Order No. 1920, 187 FERC ¶ 61,068 at PP 275–279.

[528] 16 U.S.C. 824e(a); *see S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56 (explaining that the Commission's authority under FPA section 206 is ''broadly stated and the only question is what limits are fairly implied''; this provision is not a ''subtle device''); *id.* at 55 (''The text does not define 'practice,' although use of the word 'any' amplifies the breadth of the delegation to the Commission.''); *cf. N.Y.* v. *FERC,* 535 U.S. at 15 (upholding Order No. 888, noting that the Supreme Court has ''construed broadly'' the Commission's jurisdiction under FPA section 201).

[529] *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (discussing the application of *EPSA* and related precedent to Order No. 1920 as confirming that the Commission is acting within its authority).

[530] *See EPSA,* 577 U.S. at 290 (''ensur[ing] effective transmission of electric power'' is one of the ''core objects'' of the FPA); *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 57.

in *West Virginia*) to its limits, thereby stripping the relevant term of meaning.

176. Also, unlike the provision at issue in *West Virginia,* FPA section 206 is not a rarely used provision; the Commission has acted under this authority countless times, including in significant rulemakings. This includes the Commission's landmark Order No. 888, in which the Commission addressed fundamental shifts in the landscape of the electric industry by requiring functional unbundling of wholesale generation and transmission services and imposing a similar open access requirement on unbundled retail transmission in interstate commerce,[531] as well as oversight of those processes and cost allocation via more targeted FPA section 206 complaints and Commission-initiated FPA section 206 proceedings.[532] The Supreme Court upheld Order No. 888 order, underscoring the breadth of the Commission's authority under FPA section 206. The Commission's exercise of this authority in the field of transmission planning processes and cost allocation is, itself, far from unprecedented considering the Commission's issuance of Order Nos. 890 and 1000, upon which Order No. 1920 now builds.[533] In Order No. 890, the Commission required—among other things—that public utility transmission providers' local transmission planning processes satisfy nine transmission planning principles to ensure that transmission planning processes were just and reasonable and not unduly discriminatory and preferential.[534] The Commission's next step, Order No. 1000, sought to further ensure that transmission planning and cost allocation requirements embodied in the *pro forma* OATT could facilitate the development of more efficient or cost-effective regional transmission facilities.[535] Order No. 1920 is a continuation of these prior efforts to ensure that transmission planning and cost allocation processes support the reliable and cost-effective operation of the transmission grid, by addressing identified deficiencies in those processes that render Commission-jurisdictional rates unjust and unreasonable.

177. Turning to the agency action at issue, Order No. 1920 is not an ''elephant'': while it addresses a significant problem, it does so through an improvement of the already existing Commission-jurisdictional regional transmission planning and cost allocation processes, building on and consistent with the Commission's exercise of authority in past actions,[536] and is not aimed at areas of reserved state authority. Rehearing requests arguing to the contrary—and particularly those claiming that the Commission is attempting to control or influence the resource mix or install itself as a national integrated resource planner—are based on mischaracterizations or misunderstandings of Order No. 1920, as discussed above.[537] Order No. 1920 is well within the Commission's ordinary remit and technical expertise of regulating practices affecting interstate transmission rates, unlike the cases discussed above which involved agency forays into areas well beyond their ordinary purview, such as EPA regulating the generation resource mix, Occupational Safety and Health Administration (OSHA) regulating the general public health, or the IRS addressing health insurance policy. Nor is this an instance in which the Commission has acted against a backdrop of contrary congressional action.[538]

178. Moreover, the Commission in Order No. 1920 acted in a fundamentally *responsive* capacity to require more effective transmission planning processes and cost allocation to ensure cost-effective and reliable Long-Term Regional Transmission Planning in light of preexisting forces beyond the Commission's control that give rise to transmission needs.[539] This stands in contrast to cases in which the Supreme Court has applied the major questions doctrine, which involved agency actions that, in themselves, affirmatively and proactively caused the transformative consequences that the Court identified as demonstrative of extravagant exercises of agency power.[540] For similar reasons, it is incorrect to ascribe to Order No. 1920, which aims to ensure that Long-Term Transmission Needs are met more efficiently and cost-effectively, the economic consequences associated with the construction of new transmission infrastructure, as the need for this infrastructure would still exist independent of Order No. 1920.[541]

[531] *See N.Y.* v. *FERC,* 535 U.S. at 11, 17.

[532] *See, e.g., Pub. Serv. Elec. & Gas Co.* v. *FERC,* 989 F.3d 10, 15 (D.C. Cir. 2021) (denying petitions for review of Commission order, under FPA section 206, regarding cost allocation for the Artificial Island Project); *Coal. of MISO Transmission Customers* v. *Midcontinent Indep. Sys. Operator, Inc.,* 172 FERC ¶ 61,099, 61,770 (2020) (denying complaint, under FPA section 206, challenging MISO's location-based cost allocation method for Baseline Reliability Projects); *City Utilities of Springfield, Mo.* v. *Sw. Power Pool, Inc.,* 168 FERC ¶ 61,085, 61,467 (2019) (denying complaint, under FPA section 206, asserting that SPP's administration of the unintended consequences review process for SPP's allocation of the costs of transmission facilities was unjust, unreasonable, unduly discriminatory, or preferential); *N. Ind. Pub. Serv. Co.* v. *Midcontinent Indep. Sys. Operator, Inc.,* 155 FERC ¶ 61,058 (2016) (granting in part and denying in part a complaint under FPA section 206 requesting that the Commission reform the interregional transmission planning process of the Joint Operating Agreement between MISO and PJM); *Monongahela Power Co.,* 156 FERC ¶ 61,134 (2016) (instituting a proceeding under FPA section 206 to determine whether PJM transmission owners are complying with their Order No. 890 transmission planning obligations), *order accepting in part proposed tariff revisions and requiring tariff revisions,* 162 FERC ¶ 61,129 (2018).

[533] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 14–19, 47–48, 255; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 58 (''Commission-mandated transmission planning is not new. [Order No. 1000] builds on Order No. 890's requirements in light of changed circumstances and is simply the next step in a series of related reforms that began no later than Order No. 888.'' (citation omitted)).

[534] *See* Order No. 890, 118 FERC ¶ 61,119 at PP 418–601 (requiring, among other things, that local transmission planning processes 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); Order No. 1920, 187 FERC ¶ 61,068 at PP 14, 277.

[535] Order No. 1000, 136 FERC ¶ 61,051 at PP 11–12, 42–44; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 3–6; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 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.'').

[536] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 278 (describing the rule as implementing ''incremental process improvements'').

[537] *See supra* Federal/State Division of Authority section.

[538] Arguments to the contrary suggesting, for example, that the Commission is attempting to implement the ''Green New Deal,'' rest on the incorrect premise that the Commission is attempting to preferentially favor renewable resources or influence the generation mix. Moreover, even the references cited in the rehearing requests describe the ''Green New Deal'' as a broad set of goals aimed at achieving net zero carbon emissions, without specific policies, rather than a specific proposal to enact the sort of transmission planning process and cost allocation reforms at issue in Order No. 1920. *See, e.g.,* Arizona Commission Rehearing Request at 4–5.

[539] *See supra* Federal/State Division of Authority section (noting that these forces would continue to exist, driving transmission needs, even absent Commission action).

[540] *See, e.g., West Virginia,* 597 U.S. at 721, 724–25 (addressing EPA rule seeking to ''substantially restructure the American energy market''); *Nat'l Fed'n of Indep. Bus.,* 595 U.S. at 117 (addressing agency rule requiring vaccination or medical testing); *UARG,* 573 U.S. at 321–22 (addressing agency change in statutory interpretation subjecting millions of sources to permitting requirements).

[541] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 278 (''The incremental process improvements required by the final rule, however, do not

179. In particular, arguments asserting that Order No. 1920 will impose ''billions or trillions of dollars in transmission cost[s]'' [542] claims that attempt to link the transmission costs of achieving a ''net zero'' carbon emission policy as ''caused by Order No. 1920'' [543] are not supported by the record and, instead, depend entirely on an unfounded logical leap. These arguments incorrectly portray the consequences of decisions made by other actors,[544] which represent preexisting and independent forces driving transmission needs that are outside of the Commission's control,[545] as attributable to Order No. 1920. As noted above, such arguments fundamentally reverse cause and effect by mischaracterizing Order No. 1920's process-focused requirements that transmission providers adequately *plan* for these drivers of Long-Term Transmission Needs—which requirements do not seek to achieve any substantive outcome or direct the construction of any particular transmission facilities—as *causing* these transmission needs.[546] This has no basis in fact. The drivers of these transmission needs (including those that flow from the policy decisions of actors lawfully entitled to make such choices) and the costs associated with building transmission infrastructure to meet such needs will exist independent of Order No. 1920's requirements. Indeed, because a major focus of Order No. 1920 is ensuring that more efficient or cost-effective transmission facilities are evaluated and selected, not only would these needs still exist absent the Commission's action but we expect that meeting these needs would impose *higher* costs on ratepayers.

180. We therefore continue to conclude that Order No. 1920 is not a transformative exercise of Commission authority, whether in magnitude or character, and FPA section 206 is not a surprising basis for the Commission's action, meaning that the major questions doctrine does not apply here.[547] The Supreme Court's decision in *EPSA* and D.C. Circuit decisions in *California Independent System Operator* v. *FERC* [548] and *South Carolina Public Service Authority* v. *FERC* further confirm the inapplicability of the major questions doctrine to Order No. 1920. Each of those cases addressed the scope of the Commission's authority under FPA section 206 over ''practice[s] . . . affecting'' rates, the same grant of statutory authority supporting issuance of Order No. 1920, and are thus of particular significance here.[549]

181. In *EPSA* and *CAISO,* the Courts' statutory construction limiting the Commission to regulating practices ''directly affecting'' rates was motivated by the same concern animating the major questions doctrine: effectuating congressional intent by ensuring that the Commission's exercise of this authority was reasonably constrained by more than the definitional possibilities as to what constitutes a ''practice . . . affecting'' rates.[550] *South Carolina Public Service Authority* v. *FERC* considered the scope of this authority as applied to the same context presented here, transmission planning and cost allocation processes, in reviewing the highly similar Order No. 1000. The court held that ''[r]eforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities is not the kind of interpretive 'leap' that concerned the court in *CAISO* but rather involves a core reason underlying Congress' instruction in [FPA] Section 206.'' [551] It likewise distinguished *MCI*—one of the cases the Supreme Court in *West Virginia* discussed as part of the lineage of the major questions doctrine—holding that FPA section 206 ''cannot be fairly viewed as the type of 'subtle device' at issue'' in that case.[552]

182. Thus, *EPSA* and *CAISO* reflect that the Supreme Court and the D.C. Circuit already have construed the statutory grant of authority to the Commission over practices affecting rates in FPA section 206 as imposing guardrails to ensure consistency with congressional intent and to avoid the use of this authority in ways that would implicate the major questions doctrine. *South Carolina Public Service Authority* v. *FERC,* in turn, applied these guardrails in the same context as Order No. 1920 and found that the Commission was acting within its statutory authority to address ''a core reason underlying Congress' instruction in [FPA] Section 206.'' [553] Particularly given the major questions doctrine's focus on discerning congressional intent as to the scope of a legislative delegation,[554] these cases further support our conclusion (in addition to the discussion already set forth) that the major questions doctrine does not require enhanced skepticism of Order No. 1920.[555]

183. We are, therefore, unpersuaded by arguments that the major questions doctrine should apply to Order No. 1920. Claims that Order No. 1920 presents a major question because the Commission has overstepped the jurisdictional boundaries set forth in the FPA and intruded into areas of state

fundamentally change the economic or political stakes of ensuring that Commission-jurisdictional rates remain just and reasonable.''); *id.* PP 92–93; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 51 (noting the expense associated with construction of transmission infrastructure at the time of the promulgation of Order No. 1000). No case applying the major questions doctrine has done so solely based on the economic consequences of the agency action at issue or suggested that agencies are not empowered to address significant problems falling within their general grants of statutory authority. *Cf., e.g., N.Y.* v. *FERC,* 535 U.S. at 11, 17 (affirming Commission order adopting reforms restructuring electricity markets); *Flyers Rts. Educ. Fund, Inc.* v. *U.S. Dep't of Transp.,* 810 F. App'x 1, 3 (D.C. Cir. 2020) (explaining that *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009) ''permits, but does not require, an agency to act incrementally''); *WildEarth Guardians* v. *EPA,* 751 F.3d 649, 655–56 (D.C. Cir. 2014) (summarizing *Defs. of Wildlife* v. *Gutierrez,* 532 F.3d 913 (D.C. Cir. 2008), upholding a decision to focus on a comprehensive approach). Creating such a rule would be inconsistent with the Supreme Court's discussion of the history of the major questions doctrine reflecting its application only in extraordinary cases, and then only upon a detailed consideration of the statutory context. *See West Virginia,* 597 U.S. at 721.

[542] Undersigned States Rehearing Request at 15; *see* Designated Retail Regulators Rehearing Request at 15–16.

[543] Arizona Commission Rehearing Request at 16.

[544] In particular, Order No. 1920 is neutral on the policy choices that may drive certain of these decisions, including whether ''net zero'' is an appropriate policy goal; these questions are not for the Commission to resolve.

[545] *See supra* Order No. 1920 Does Not Attempt to Control the Generation Mix or Intrude in Areas of State Authority section (explaining that Order No. 1920 is resource neutral, treating these exogenous forces that drive Long-Term Transmission Needs as inputs to Long-Term Regional Transmission Planning).

[546] *See supra* Order No. 1920 Does Not Attempt to Control the Generation Mix or Intrude in Areas of State Authority section.

[547] Order No. 1920, 187 FERC ¶ 61,068 at PP 278–279.

[548] 372 F.3d 395 (D.C. Cir. 2004) (*CAISO*).

[549] *See EPSA,* 577 U.S. at 277–78; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56–57; *CAISO,* 732 F.3d at 399–404.

[550] *See EPSA,* 577 U.S. at 277–78 (adopting the ''directly affecting'' construction of FPA section 206(a) because ''[t]aken for all it is worth, that statutory grant could extend FERC's power to some surprising places'' given that markets in all of electricity's inputs might affect the supply of power and ''markets in just about everything'' might affect load-serving entities' demand); *CAISO,* 372 F.3d at 400 (explaining that ambiguity, in statutory construction, is not a creature of definitional possibilities but of statutory context); *id.* at 401 (rejecting the argument that there is an ''infinitude of acceptable definitions for what constitutes a 'practice' to give [the Commission] the authority to regulate anything done by or connected with a regulated utility, as any act or aspect of such an entity's corporate existence could affect, in some sense, the rates'').

[551] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 57.

[552] *Id.* at 56.

[553] *Id.* at 57.

[554] *See West Virginia,* 597 U.S. at 721–23.

[555] *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (explaining, as discussed in Order No. 1920 and not disputed on rehearing, that Order No. 1920 is consistent with the Supreme Court's decision in *EPSA*).

authority [556] are mistaken because the Commission has acted well within its authority to regulate practices affecting interstate transmission rates, honoring the jurisdictional divide set forth by Congress in the FPA.[557] Arguments that the Commission is misusing the FPA to enact preferential policies [558] are misplaced for the same reasons. As already discussed, arguments invoking the purported economic consequences of Order No. 1920 [559] misattribute the costs of constructing transmission infrastructure to Order No. 1920. Regardless, while the economic impact is relevant to this inquiry, the major questions doctrine is a nuanced, context-specific doctrine that does not require clear congressional authorization for every agency action that may have significant economic consequences or addresses a significant problem.[560]

184. We also are not persuaded by SERTP Sponsors' arguments that, unless the Commission grants its requests for clarification, Order No. 1920 runs afoul of the major questions doctrine, encroaches on state jurisdiction, or otherwise exceeds the Commission's authority. SERTP Sponsors do not clearly set forth the basis for many of their purported concerns regarding the Commission's statutory authority or application of the major questions doctrine, or even which arguments raise these concerns. For instance, while SERTP Sponsors identify Sections II.A.1 and II.C.3 of their argument as particularly raising these concerns,[561] in their Statement of Issues they more broadly state that the clarifications in ''Sections II.A and II.C'' of their argument are necessary to avoid intruding into state jurisdiction or application of the major questions doctrine.[562] But it is far from clear, and SERTP Sponsors do not explain, why many of the requested clarifications in Sections II.A and II.C would be necessary to avoid SERTP Sponsors' stated concerns about the Commission failing to afford adequate respect to state-approved integrated resource plans and load-serving entities' supply obligations or otherwise implicate concerns that the Commission is intruding into state jurisdiction.[563] Certain of SERTP Sponsors' other claims that, absent clarification, other aspects of Order No. 1920 would exceed the Commission's authority, are single-sentence assertions that provide little or nothing to illuminate why they believe this is the case.[564]

185. We address SERTP Sponsors' requests for clarification on their substance at various points in our discussion below. In several instances, we find that SERTP Sponsors have failed to plead their arguments that, absent their requested clarification, the Commission has exceeded its authority with the specificity required on rehearing, and we reject them on that basis.[565] Regardless, to the extent that we do not grant those requests for clarification, whether in whole or in part, we find that the explanations in Order No. 1920 and herein establishing that Order No. 1920 is within the Commission's authority, does not unlawfully intrude into state areas of reserved authority, and does not implicate the major questions doctrine render SERTP Sponsors' arguments to the contrary unpersuasive. Where we believe further additional explanation is warranted in response to addressing a specific request for clarification made by SERTP Sponsors, we provide that explanation in conjunction with addressing the relevant request for clarification.

D. Other Issues

1. Requests for Rehearing

186. Several of the parties seeking rehearing argue that Order No. 1920 is not supported by the D.C. Circuit's decision in *South Carolina Public Service Authority* v. *FERC,* asserting that the Commission has attempted to direct substantive outcomes affecting the generation resource mix. Arizona Commission contends that Order No. 1000 ''confined mandatory consideration [of factors affecting transmission needs] to pertinent laws and regulations, whereas Order No. 1920 now mandates consideration of broader 'policy goals,''' which are ''more nebulous political agendas susceptible to significant fluctuations.'' [566] It contends that the Commission ''is not authorized to compel Arizona to use

[556] *See* Undersigned States Rehearing Request at 14–15 (citing *Ala. Ass'n of Realtors* v. *HHS,* 594 U.S. at 764 (finding that one consideration favoring application of the major questions doctrine was that the agency action ''intrudes into an area that is the particular domain of state law: the landlord-tenant relationship'')); *id.* at 16 (arguing that the Commission was attempting to determine ''what resources should be powering the grid twenty years into the future''); Designated Retail Regulators Rehearing Request at 15–19 (similar); Arizona Commission Rehearing Request at 5–6; Utah Commission Rehearing Request at 7–8; *cf.* Ohio Commission Federal Advocate Rehearing Request at 20 (''FERC points to no 'clear congressional authorization' for it to use its power under the FPA to facilitate federal, state, Tribal, local, and corporate policies. . . .'').

[557] *See supra* Federal/State Division of Authority section; Order No. 1920, 187 FERC ¶ 61,068 at PP 263–267. We also reiterate, in response to arguments that the Supreme Court in *West Virginia* found it '' 'highly unlikely that Congress would leave to agency discretion the decision of how much . . . generation there should be over the coming decades' on a resource-by-resource basis,'' Undersigned States Rehearing Request at 15 (quoting *West Virginia,* 597 U.S. at 729; also citing ''the breadth of the transmission grid [and] the importance of electricity in everyday life''), that ''the Court did not determine that energy policy and the mix of generation resources are *in every instance* a major question.'' Order No. 1920, 187 FERC ¶ 61,068 at P 276; *see also id.* PP 277–278. In any event, Order No. 1920 still would not implicate the major questions doctrine because it is not aimed at this end.

[558] *See* Undersigned States Rehearing Request at 16–17; Designated Retail Regulators Rehearing Request at 16–17; Arizona Commission Rehearing Request at 3 n.2, 4, 20.

[559] *See* Undersigned States Rehearing Request at 14–15; Designated Retail Regulators Rehearing Request at 15–16; Utah Commission Rehearing Request at 8; *cf.* Arizona Commission Rehearing Request at 16 (citing the cost of achieving net-zero on the transmission grid).

[560] *See id.*; *cf. also* Arizona Commission Rehearing Request at 6 (''Under *West Virginia,* a major doctrinal change in the law, and the making of a federal rule that fundamentally reshapes policy, has to be done pursuant to an express statement of Congress''); Idaho Commission Rehearing Request at 6.

[561] SERTP Sponsors Rehearing Request at 39; *see also id.* at 41, 43 (issue statements 1 and 15).

[562] *Id.* at 44–45.

[563] *See, e.g., id.* at 7–8 (arguing that states should be allowed to lengthen the time, upon agreement or motion, to reach an agreement as to cost allocation method); *id.* at 8 (requesting clarification on voluntary funding opportunities); *id.* at 11–12 (arguing that Long Term Transmission Needs have been defined in a circular fashion and that transmission providers should have discretion to use their expertise where they lack certain information); *id.* at 12–17 (requesting clarification that the factors affecting a single assumption will not necessarily have an additive effect; clarification on how specific factors will be identified; clarification on whether the Commission has expanded what constitutes legally binding obligations; and rehearing regarding adoption of Factor Category Seven).

[564] *See id.* at 41 (''Absent the requested clarification in section II.A.2, the six-month period permitted for states to negotiate an extension of the time period [*sic*] for negotiating *ex ante* or *ex post* state agreements on cost allocation, Order No. 1920 is contrary to FPA section 201, is *ultra vires,* and arbitrary and capricious''); *id.* (''Absent the requested clarification in section II.A.3, Order No. 1920 is contrary to FPA section 201 because it effectively mandates selection and/or construction of an LTRTF.''); *id.* at 43 (''Absent the clarifications requested in section II.C.2.d, requiring the utilization of Factor Category Seven intrudes into matters involving retail customers subject to state regulation, thereby being ultra vires and contrary to FPA section 201.'').

[565] *See ZEP Grand Prairie Wind, LLC,* 183 FERC ¶ 61,150, at P 10 (2023); *see also Ind. Util. Regul. Comm'n* v. *FERC,* 668 F.3d 735, 736 (D.C. Cir. 2012).

[566] Arizona Commission Rehearing Request at 12–13 (arguing also that Arizona law ''does not allow the [Arizona Commission] to adopt, create, or mandate energy policy goals, and Order No. 1920's effort to compel the [Arizona Commission] to do so is unlawful'' and that Order No. 1920's approach will lead to unjust cost allocations wherein states without renewable policy objectives must absorb costs generated by the transmission of renewable energy).

specific energy resources.'' [567] Montana Commission, West Virginia Commission, and Wyoming Commission argue that Order No. 1000 was upheld in *South Carolina Public Service Authority* v. *FERC* because of its light touch, which did not mandate a ''backstop'' *ex ante* cost allocation method to a voluntary state agreement, whereas Order No. 1920 has placed states in the untenable position of either agreeing to unjust and unreasonable cost allocations or having that burden foisted on them by default.[568] They further assert that Order No. 1920's ''influence over the selection of transmission projects will inevitably affect resource planning and selection at the state level,'' invading the jurisdiction of the states.[569] Utah Commission argues that Order No. 1920, unlike Order No. 1000, ''patently dictates outcomes and cost allocation and does so to discriminate and favor the policy preferences of certain preferred stakeholders.'' [570]

187. Undersigned States and Designated Retail Regulators argue that Order No. 1920 ''mandates transmission planning criteria that marginalize the input from Relevant Electric Retail Regulatory Authorit[ies] [(RERRAs)] in transmission planning, instead favoring selected generation.'' [571] In particular, they argue that Order No. 1920 adopts monolithic nationwide criteria that remove the states' role in planning and cost allocation, and that those criteria are ''designed to allow the preferred policy goals of certain states, utilities, and corporate interests to dictate transmission planning for all,'' rather than prioritizing reliability and consumer impacts.[572] Similarly, Georgia Commission argues that Order No. 1920 ''violates the states' reserved decision-making power by requiring that the states measure their long-term transmission plans against seven factors identified in the Order.'' [573]

188. Relatedly, Montana Commission, West Virginia Commission, and Wyoming Commission argue that Order No. 1920 undermines states' role in transmission planning and ratemaking, and does not result in just and reasonable rates.[574] In particular, they assert that under Order No. 1920, transmission providers would be required to plan projects while considering the policy goals of various states (*e.g.,* decarbonization), such that ''the leading transmission projects may not be the most economical, let alone necessary, but for the policy goals of other states.'' [575] They contend that the costs allocated to retail customers may exceed the benefits that state policy recognizes from regional transmission projects, such that state commissions ''would be forced to either assign unjust and unreasonable rates to retail customers, or deny the utility a potentially significant portion of its expected cost recovery.'' [576] Arizona Commission argues that Order No. 1920 usurps state authority mandating that it ''apply rates that are fair and reasonable and not to cost share with rate payers who did not cause (and do not benefit from) a particular cost.'' [577]

189. Arizona Commission also states that it owes its existence to the Arizona Constitution and that it has plenary power to set just and reasonable rates and charges collected by public service corporations.[578] It asserts that even the Arizona state legislature is ''precluded by state constitutional law from legislating rate making decisions,'' and contends that, by the same token, the federal government ''is certainly precluded from directing Arizona utilities to adopt energy plans that could cost hundreds of billions of dollars to Arizona consumers.'' [579]

190. On rehearing, Undersigned States again argue that Order No. 1920 is beyond the Commission's authority because, if the FPA were interpreted to authorize the rule, it ''would likely violate the Constitution's equal sovereignty doctrine.'' [580] They argue that Order No. 1920 ''sets up a scheme where one state can effectively require other states to subsidize their own public policy agenda—a core, sovereign state function.'' [581] Undersigned States also now bring a single sentence argument that ''even if the Rule were supported by statutory authorization . . . then it would violate the nondelegation doctrine,'' on the theory that Congress is entirely precluded from delegating any ''major policy question[s]'' to agencies.[582]

191. Ohio Commission Federal Advocate contends that in issuing Order No. 1920 the Commission has violated the Commerce Clause because Commission authority ''does not reach . . . attempts to use it to assist utilities and corporations with meeting their goals and commitments.'' [583] It particularly asserts that ''[t]he U.S. Supreme Court has held that in the absence of federal legislation, commerce is generally open to control by states'' and that Order No. 1920 will disproportionately benefit certain states, *e.g.,* those with policies in favor of electrification of the transportation and building sectors.[584]

2. Commission Determination

192. We find that arguments that Order No. 1920 is not supported by the D.C. Circuit's decision in *South Carolina Public Service Authority* v. *FERC* upholding Order No. 1000 are

[567] *Id.* at 13.

[568] *See* Montana Commission Rehearing Request at 2–4; West Virginia Commission Rehearing Request at 10–12; Wyoming Commission Rehearing Request at 2–4.

[569] *See* Montana Commission Rehearing Request at 4; West Virginia Commission Rehearing Request at 12; Wyoming Commission Rehearing Request at 4.

[570] Utah Commission Rehearing Request at 8 n.17.

[571] Undersigned States Rehearing Request at 7–8; *see id.* at 24–26; Designated Retail Regulators Rehearing Request at 8, 24–26.

[572] Undersigned States Rehearing Request at 24; *id.* at 26 (''With its rigid planning and cost allocation criteria, the Rule will result in the imposition of massive transmission costs necessary to accomplish certain states' policy goals upon other states.''); Designated Retail Regulators Rehearing Request at 24–26 (similar).

[573] Georgia Commission Rehearing Request at 4.

[574] *See* Montana Commission Rehearing Request at 6–7 (arguing that a significant share of the costs of transmission facilities are allocated to retail customers, a question which is best left to the expertise of the states); West Virginia Commission Rehearing Request at 9–10; Wyoming Commission Rehearing Request at 6–8.

[575] *See* Montana Commission Rehearing Request at 6–7; West Virginia Commission Rehearing Request at 9–10; Wyoming Commission Rehearing Request at 7–8.

[576] Montana Commission Rehearing Request at 6–7 (noting that the Montana Commission typically conducts *post hoc* rather than *ex ante* rate reviews and that it is not clear that Order No. 1920 is designed to accommodate this process); West Virginia Commission Rehearing Request at 9–10; Wyoming Commission Rehearing Request at 7–8.

[577] Arizona Commission Rehearing Request at 20–22 (claiming that Order No. 1920 ''usurps the Arizona Constitution and its methodology'' because it ''provides several factors that must be considered in transmission planning and cost allocation'' which ''include neither the fairness nor reasonableness of the costs nor any consideration of who causes the costs mandated by the FPA'').

[578] *Id.* at 7–9.

[579] *Id.* at 8–9.

[580] Undersigned States Rehearing Request at 18–19.

[581] *Id.* (arguing that Order No. 1920 subverts the democratic process, encroaches on state prerogatives, and is inconsistent with principles of cooperative federalism (citing *Coyle* v. *Smith,* 221 U.S. 559, 567 (1911); *Franchise Tax Bd.* v. *Hyatt,* 578 U.S. 171, 179 (2016); *Stearns* v. *Minn.,* 179 U.S. 223, 245 (1900); *Shelby Cnty.* v. *Holder,* 570 U.S. 529, 544 (2013)).

[582] *Id.* at 17–18 (citing *Paul* v. *U.S.,* 140 S. Ct. 342, 342 (2019) (Mem.) (Kavanaugh, J., statement respecting denial of certiorari); *Indus. Union Dep't, AFL–CIO* v. *Am. Petroleum Inst.,* 448 U.S. 607, 685–86 (1980) (Rehnquist, J., concurring in judgment); *A.L.A. Schechter Poultry Corp.* v. *U.S.,* 295 U.S. 495 (1935)).

[583] Ohio Commission Federal Advocate Rehearing Request at 18–19 (citing *City of Phila.* v. *N.J.,* 437 U.S. 617, 623 (1978); *Gen. Motors Corp.* v. *Tracy,* 519 U.S. 278, 300 (1997); *H. P. Hood & Sons, Inc.* v. *Du Mond,* 336 U.S. 525 (1949); *N.Y.* v. *U.S.,* 505 U.S. 144 (1992); *Printz* v. *United States,* 521 U.S. 898 (1997)).

[584] *Id.* (also arguing that Order No. 1920 will also benefit certain types of generation developers).

erroneous because, as the court in that case put it, they ''misperceive[ ] what the Commission has required in the Final Rule.'' [585] Order No. 1920 is directed toward ensuring just and reasonable rates by requiring Long-Term Regional Transmission Planning, including requiring transmission providers to evaluate which Long-Term Regional Transmission Facilities will more efficiently or cost-effectively address Long-Term Transmission Needs.[586] As in *South Carolina Public Service Authority* v. *FERC,*[587] the Commission has declined to impose obligations to ''mandate development of any particular transmission facility,'' [588] change applicable siting requirements and processes,[589] or ''change existing mechanisms for cost-recovery through retail rates.'' [590] Order No. 1920 ''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.'' [591] Under Order No. 1920, like Order No. 1000, ''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.'' [592] The Commission also maintains Order No. 1000's light touch as to regional cost allocation: ''[i]t does not dictate how costs are to be allocated. Rather, the Rule provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes.'' [593]

193. We disagree with the arguments in the rehearing requests that Order No. 1920 attempts to direct substantive outcomes, including as to the generation resource mix.[594] As already explained, Order No. 1920 remains process-focused and does not seek to achieve particular substantive outcomes, influence or direct the generation mix, preferentially favor certain transmission facilities, or require unlawful subsidization of state policies.[595] While it requires consideration of certain categories of factors in assessing Long-Term Transmission Needs,[596] these factors are resource-neutral and, within the broad parameters set by Order No. 1920, transmission providers have significant discretion in developing Long-Term Scenarios that further precludes the Commission from attempting to dictate outcomes.[597] Moreover, as described, transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to state public policies in Long-Term Regional Transmission Planning assumptions.

194. We disagree with claims that Commission has departed from the ''light touch'' of Order No. 1000 because Order No. 1000 did not mandate a ''backstop'' *ex ante* cost allocation method to a voluntary State Agreement Process.[598] As *South Carolina Public Service Authority* v. *FERC* recognized and upheld, Order No. 1000 required transmission providers to file an *ex ante* cost allocation method.[599] Order No. 1920 did not diminish states' role compared to Order No. 1000 but, instead, increased the available opportunities for robust participation by Relevant State Entities to seek to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[600] By virtue of these requirements, Order No. 1920 is more solicitous of state input and uses an even lighter touch than Order No. 1000 in this respect. As discussed elsewhere,[601] we take further steps in this rehearing order to strengthen states' role in Long-Term Regional Transmission Planning and cost allocation for Long-Term Regional Transmission Facilities.

195. We are also not persuaded by arguments that Order No. 1920 exceeds the Commission's authority because it thwarts the role of RERRAs [602] or unlawfully intrudes on the authority of state bodies that regulate retail rates.[603] Order No. 1920 ''does not change existing mechanisms for cost-recovery through retail rates,'' but, instead, regulates transmission planning and cost allocation processes falling within the Commission's jurisdiction.[604] To the extent that Order No. 1920 might affect retail rates or other areas of state authority, this does not defeat the Commission's authority; as a valid exercise of the Commission's jurisdiction over practices affecting interstate transmission rates, Order No. 1920 is lawful notwithstanding such effects.[605] Finally, assertions that the

[585] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 57.

[586] Order No. 1920, 187 FERC ¶ 61,068 at PP 134, 667, 721–723.

[587] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 57–58 (explaining that the Commission did not impose obligations to build or mandatory processes to construct transmission facilities in the regional transmission plan and disavowed that it was purporting to determine what needs to be built, where it needs to be built, and who needs to build it); *see id.* at 62 (''The orders neither require facility construction nor allow a party to build without securing necessary state approvals.'').

[588] Order No. 1920, 187 FERC ¶ 61,068 at P 257; *see id.* P 419 (''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.'').

[589] *See id.* P 258.

[590] *Id.* P 259.

[591] *Id.* P 254; *see also id.* P 256 (''[W]e 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.'').

[592] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 58.

[593] *Id.* at 81; *see, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at PP 268–269, 723, 916, 954, 1291–1294.

[594] *See* Arizona Commission Rehearing Request at 12–13; Montana Commission Rehearing Request at 3–4; West Virginia Commission Rehearing Request at 10–12; Wyoming Commission Rehearing Request at 2–4; Utah Commission Rehearing Request at 8 n.17.

[595] *See infra* Requirement to Incorporate Categories of Factors section.

[596] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 300 (''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 rule.'').

[597] *See infra* Requirement to Incorporate Categories of Factors section.

[598] *See* Montana Commission Rehearing Request at 2–4; West Virginia Commission Rehearing Request at 10–12; Wyoming Commission Rehearing Request at 2–4.

[599] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 53 (''The cost-allocation reforms in Order No. 1000 require each transmission provider to include in its OATT a method (or set of methods) for allocating *ex ante* the costs of new regional transmission facilities that complies with six regional cost allocation principles.'' (citing Order No. 1000, 136 FERC ¶ 61,051 at P 558)); *see id.* at 82–87 (rejecting challenges to the Commission's authority to adopt such reforms).

[600] *See id.* PP 5, 268, 1291.

[601] *Infra* Transmission Planning Horizon section; Obligation to File an *Ex Ante* Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section.

[602] *See* Undersigned States Rehearing Request at 7–8; Designated Retail Regulators Rehearing Request at 8, 24–26; Georgia PSC Rehearing Request at 4.

[603] *See* Montana Commission Rehearing Request at 6–7; West Virginia Commission Rehearing Request at 9–10; Wyoming Commission Rehearing Request at 6–8; Arizona Commission Rehearing Request at 20–22 (arguing that the primary focus of transmission planning and cost allocation has been reliability and low cost, and that Order No. 1920 introduces other considerations).

[604] Order No. 1920, 187 FERC ¶ 61,068 at P 259.

[605] *See supra* Federal/State Division of Authority section; *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.'' (emphasis added))); *see also* Arizona Commission Rehearing Request at 20–22 (claiming that Order No. 1920 ''usurps the Arizona Constitution and its methodology'' and otherwise conflicts with state law); U.S. Const. Art. VI (''This Constitution, and the Laws of the United States which shall be made in Pursuance thereof . . . shall be the supreme Law of the Land . . . any

Commission is attempting to dictate substantive outcomes or prefer certain energy resources or policies or that Order No. 1920 does not comport with principles of cost causation [606] are not convincing for the reasons already explained.[607]

196. We are also not persuaded by Undersigned States' argument [608] that if Order No. 1920 were authorized by the FPA, the FPA would violate equal sovereignty principles. The Commission in Order No. 1920 explained at length its reasons for rejecting that argument.[609] On rehearing, Undersigned States repeat their arguments from their comments on the NOPR while failing to engage with, let alone rebut, the Commission's reasoning in Order No. 1920.[610] We therefore sustain Order No. 1920's rejection of this argument for the reasons stated therein. We particularly note that Undersigned States have pointed to no precedent applying the equal sovereignty doctrine in circumstances comparable to those here.[611]

197. Also unpersuasive is Undersigned States' nondelegation argument.[612] To begin with, this argument was not raised prior to rehearing, as required by the Commission's Rule of Practice and Procedure 713(c)(3).[613] We typically do not consider arguments raised for the first time on rehearing, unless those arguments could not have been previously presented, *e.g.,* claims based on information that only recently became available or concerns prompted by a change in material circumstances.[614] Commenters had the opportunity to raise this argument, but did not do so.[615]

198. In any event, a statute does not violate the nondelegation doctrine so long as Congress has set forth an ''intelligible principle'' to guide the delegee's exercise of authority.[616] Undersigned States fail to apply (or even acknowledge) this test, address the precedent setting it forth, or engage with the text of the FPA.[617] Instead, distinct from their major questions doctrine argument, they assert a *per se* bar on Congress delegating ''major policy questions'' to agencies.[618] They cite no case adopting this sweeping rule,[619] and we therefore decline to apply this approach here.[620] Moreover, Undersigned States' single-sentence argument fails to explain the parameters of this test or how we would apply it to the statutory text of the FPA or Order No. 1920. And even were we to set aside the foregoing, we would still disagree that Order No. 1920 involves the delegation of such a ''major policy question'' for the reasons stated herein and in Order No. 1920.[621]

199. Finally, Ohio Commission Federal Advocate incorrectly claims that Order No. 1920 ''violates the federal Commerce Clause'' on the theory that Order No. 1920 may disproportionately benefit commerce in certain states, which have implemented policies allegedly favored by the rule, as compared to other states.[622] As discussed above, Order No. 1920 is a valid exercise of congressionally granted authority under the FPA. It does not favor particular state policies or transmission planning outcomes, but rather takes state policies as inputs into Long-Term Regional Transmission Planning.[623] Furthermore, the precedent

Thing in the Constitution or Laws of any State to the Contrary notwithstanding.''); *NARUC,* 964 F.3d at 1186–88 (discussing the application of the Supremacy Clause in the context of the FPA in rejecting an argument that a Commission regulation unlawfully regulated matters falling within state authority).

[606] *See, e.g.,* States Rehearing Request at 7–8, 24; Designated Retail Regulators Rehearing Request at 8, 25–26; Georgia PSC Rehearing Request at 4; Arizona Commission Rehearing Request at 22; Utah Commission Rehearing Request at 9.

[607] *See supra* Federal/State Division of Authority section(explaining that Order No. 1920 is not directed at achieving substantive outcomes and that the categories of factors are resource-neutral); *supra* Order No. 1920 Does Not Require Unlawful Subsidization of State Policies section (explaining that arguments that the Commission is requiring subsidization of state policies are incorrect and unpersuasive).

[608] Undersigned States Rehearing Request at 18–19.

[609] Order No. 1920, 187 FERC ¶ 61,068 at PP 280–282 (explaining that this argument was not supported by precedent and is incorrect because Order No. 1920 does not require subsidization of other states policies or generation decisions).

[610] *See* Undersigned States Rehearing Request at 18–19; Order No. 1920, 187 FERC ¶ 61,068 at P 212 & n.535 (citing Undersigned States Reply Comments at 5–6).

[611] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 280–282. In addition to the discussion in Order No. 1920, we observe that, unlike here, the cases on which Undersigned States rely addressed the validity of direct and *de jure* limitations of the rights of certain states relative the rights provided to other states. *See Franchise Tax Bd.* v. *Hyatt,* 578 U.S. at 178 (explaining that Nevada ''has applied a special rule of law applicable only in lawsuits against its sister States''); *Shelby Cnty.* v. *Holder,* 570 U.S. at 544 (''And despite the tradition of equal sovereignty, the Act applies to only nine States (and several additional counties).''); *Coyle* v. *Smith,* 221 U.S. at 579 (''Has Oklahoma been admitted upon an equal footing with the original states? If she has, she, by virtue of her jurisdictional sovereignty as such a state, may determine for her own people the proper location of the local seat of government.''); *cf. Stearns* v. *Minn.,* 179 U.S. at 244–45 (discussing the validity of certain provisions of the enabling act admitting Minnesota to the Union, as incorporated in the Minnesota Constitution, in noting that ''a state admitted into the Union enters therein in full equality with all the others'').

[612] *See* Undersigned States Rehearing Request at 17–18.

[613] *See* 18 CFR 385.713(c)(3) (providing that any request for rehearing must ''[s]et forth the matters relied upon by the party requesting rehearing, if rehearing is sought based on matters not available for consideration by the Commission at the time of the final decision or final order'').

[614] *See Ala. Power Co.,* 179 FERC ¶ 61,128, at P 15 (2022); *KEI (Me.) Power Mgmt. (III) LLC,* 173 FERC ¶ 61,069, at P 38 n.77 (2020); *Tex. E. Transmission, LP,* 141 FERC ¶ 61,043, at P 19 (2012) (''We do so because (1) our regulations preclude other parties from responding to a request for rehearing and (2) such behavior is disruptive to the administrative process because it has the effect of moving the target for parties seeking a final administrative decision.'' (quotation marks omitted)); *Calpine Oneta Power* v. *Am. Elec. Power Serv. Corp.,* 114 FERC ¶ 61,030, at P 7 (2006); *Iroquois Gas Transmission Sys., L.P.,* 86 FERC ¶ 61,261, at 61,949 (1999)); *Ocean State Power II,* 69 FERC ¶ 61,146, at 61,548 (1994); *NO Gas Pipeline* v. *FERC,* 756 F.3d 764, 770 (''We finally note that Jersey City's alleged constitutional claim of actual bias is also barred as untimely. Jersey City has shown us nothing of record to establish that it raised this issue before FERC's issuance of the initial order.'').

[615] *See U.S.* v. *L.A. Tucker Truck Lines, Inc.,* 344 U.S. 33, 37 (1952) (''Simple fairness to those who are engaged in the tasks of administration, and to litigants, requires as a general rule that courts should not topple over administrative decisions unless the administrative body not only has erred but has erred against objection made at the time appropriate under its practice.''); *cf. Reytblatt* v. *U.S. Nuclear Regul. Comm'n,* 105 F.3d 715, 723 (D.C. Cir. 1997) (agencies are not required to respond to untimely comments).

[616] *Whitman* v. *Am. Trucking Ass'ns,* 531 U.S. at 472 (citing *J.W. Hampton, Jr., & Co.* v. *United States,* 276 U.S. 394, 409 (1928)); *see also Fox Television Stations, Inc.,* 556 U.S. at 536; *Nat'l Postal Pol'y Council* v. *Postal Regul. Comm'n,* 17 F.4th 1184, 1192 (D.C. Cir. 2021).

[617] *Cf. Gundy* v. *United States,* 588 U.S. 128, 146 (2019) (plurality opinion) (''We have sustained authorizations for agencies to set ''fair and equitable'' prices and ''just and reasonable'' rates.'' (citing *Yakus* v. *United States,* 321 U.S. 414, 422, 427 (1944); *FPC* v. *Hope Nat. Gas Co.,* 320 U.S. 591 (1944)).

[618] *See* Undersigned States Rehearing Request at 17–18.

[619] *See id.* (citing *Paul* v. *U.S.,* 140 S. Ct. at 342 (2019) (Mem.) (Kavanaugh, J., statement respecting denial of certiorari) (expressly recognizing that ''the Court has not adopted a nondelegation principle for major questions''); *Union Dep't, AFL–CIO* v. *Am. Petroleum Inst.,* 448 U.S. at, 685–86 (Rehnquist, J., concurring in judgment) (similar); *A.L.A. Schechter Poultry Corp.* v. *United States,* 295 U.S. 495).

[620] This argument is also in tension with the Court's articulation of the major questions doctrine in *West Virginia. See* 597 U.S. at 721, 723 (explaining that the major questions doctrine applied only in extraordinary cases, based on specific statutory context and a variety of factors, and that ''delegation[s]'' to address major questions were permissible with clear congressional authorization); *cf. Paul* v. *U.S.,* 140 S. Ct. at 342 (Mem.) (Kavanaugh, J., statement respecting denial of certiorari) (recognizing that application of this test would overturn the aspect of major questions doctrine allowing Congress to ''delegate to the agency the authority both to decide the major policy question and to regulate and enforce'').

[621] *See supra* Major Questions Doctrine section; Order No. 1920, 187 FERC ¶ 61,068 at PP 253–62, 275–78.

[622] Ohio Commission Federal Advocate Rehearing Request at 18–19.

[623] *See supra* Federal/State Division of Authority section.

that Ohio Commission Federal Advocate cites does not support concluding that a generally applicable Commission rule promulgated pursuant to its authority under the FPA (itself a valid exercise of Congress's Commerce Clause authority) violates the Commerce Clause if that rule may have disparate effects on commerce in various states.[624]

V. Long-Term Regional Transmission Planning

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

1. Order No. 1920 Requirements

200. In Order No. 1920, the Commission required 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. The Commission required that Long-Term Regional Transmission Planning comply with the following Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.[625]

201. The Commission explained that Long-Term Regional Transmission Planning will enhance the existing regional transmission planning and cost allocation processes required by Order No. 1000. The Commission also stated that, except as set forth in Order No. 1920, it does not require any transmission provider to 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). As such, the Commission explained, 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.[626] The Commission also declined a request to mandate that the ''base cases'' used in Order No. 1000 regional transmission planning processes and the Long-Term Scenarios used in Long-Term Regional Transmission Planning be defined in the same process.[627]

202. The Commission further explained that Order No. 1920 does not alter the existing Order No. 1000 requirement to consider Public Policy Requirements in the regional transmission planning process, and further stated that it will instead deem transmission providers to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set for in Order No. 1920.[628] The Commission allowed transmission providers to propose in their Order No. 1920 compliance filings 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. The Commission held that transmission providers nevertheless must comply with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920, 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 Order No. 1920. The Commission required that, in their Order No. 1920 compliance filings, 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 Order No. 1920.[629]

203. The Commission also allowed 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 defined in Order No. 1920, through a combined process. The Commission required transmission providers proposing to address all of these transmission needs in a single regional transmission planning process to demonstrate that such a 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 Order No. 1920, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order Nos. 1000 and 1920. The Commission explained that, in the case that the requirements of Order Nos. 1000 and 1920 conflict, the Order No. 1920 requirements will prevail, and transmission providers must demonstrate that their proposed regional transmission planning process is consistent with or superior to the applicable Order No. 1920 requirements.[630]

204. As described further in the Implementation of Long-Term Regional Transmission Planning section below, in Order No. 1920, the Commission required transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. The Commission required transmission providers to provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, the Commission required transmission providers to address the possible interaction between the transmission planning cycle for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. The

[624] *See* Ohio Commission Federal Advocate Rehearing Request at 18–19; *Gen. Motors Corp.* v. *Tracy,* 519 U.S. at 281–82, 287–88, 311–12 (addressing whether state sales and use taxes were impermissible as discriminatory under dormant Commerce Clause or Equal Protection Clause jurisprudence; holding that the taxes violated neither provision of the Constitution); *City of Phila.* v. *N.J.,* 437 U.S. at 623 (similarly addressing issues arising under dormant Commerce Clause jurisprudence, in the absence of controlling federal legislation, particularly as to whether New Jersey could close its borders to importation of certain waste); *H.P. Hood & Sons, Inc.* v. *Du Mond,* 336 U.S. at 545 (''Since the [state] statute as applied violates the [dormant] Commerce Clause and is not authorized by federal legislation pursuant to that Clause, it cannot stand.''); *cf. Printz* v. *United States,* 521 U.S. at 935 (''We held in *New York* that Congress cannot compel the States to enact or enforce a federal regulatory program. Today we hold that Congress cannot circumvent that prohibition by conscripting the State's officers directly.''); *New York* v. *U.S.* 505 U.S. at 161 (''This litigation . . . concerns the circumstances under which Congress may use the States as implements of regulation . . . .'').

[625] Order No. 1920, 187 FERC ¶ 61,068 at P 224.

[626] *Id.* P 241.

[627] *Id.* P 246.

[628] *Id.* P 242.

[629] *Id.* P 243.

[630] *Id.* P 244.

Commission recognized 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.[631] Second, the Commission required transmission providers to address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. The Commission recognized that 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.[632]

2. Requests for Rehearing and Clarification

205. Multiple parties request rehearing and clarification on the requirement that, in their Order No. 1920 compliance filings, 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 Order No. 1920. Large Public Power requests clarification that the Commission will presume the existing regional transmission planning and cost allocation processes that transmission providers use to consider transmission needs driven by Public Policy Requirements to be just and reasonable. Large Public Power claims that this is an issue on which the Commission was not clear in Order No. 1920, because the Commission stated that Order No. 1920 ''do[es] not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process,'' that transmission providers may propose to continue using these processes, and that transmission providers proposing to do so ''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 rule.''[633] Large Public Power contends that its members see value in existing regional transmission planning processes that transmission providers use to consider transmission needs driven by Public Policy Requirements, and requests that the Commission not disrupt these processes—in particular the process conducted by NYISO. Large Public Power describes certain aspects of NYISO's regional transmission planning process and explains that the New York Commission and the Commission each have approved these processes.[634] Large Public Power therefore requests that, in reviewing transmission providers' Order No. 1920 compliance filings, the Commission presume that these existing processes are just and reasonable, and argues that the Commission should not require transmission providers and their stakeholders to face the burden of demonstrating that these processes are just and reasonable.[635] If the Commission does not grant clarification, Large Public Power requests rehearing on the ground that the Commission did not advance in Order No. 1920 any ''cogent rationale'' for treating regional transmission planning processes that consider Public Policy Requirements differently from those that plan for reliability or economic transmission needs.[636]

206. Similar to Large Public Power's rehearing request, Pennsylvania Commission argues that requiring transmission providers in Order No. 1920 to demonstrate that continued use of existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements does not interfere with or otherwise undermine Long-Term Regional Transmission Planning is an abuse of discretion, and that the Commission failed to engage in reasoned decision making.[637] Pennsylvania Commission further argues that this requirement is inconsistent with the Commission's statements that, outside the context of Long-Term Regional Transmission Planning, Order No. 1920 will not ''otherwise disturb[] the regional transmission planning structure required by Order No. 1000'' or ''inadvertently cause the re-litigation of aspects of those existing processes.''[638] Pennsylvania Commission contends that Order No. 1920 requires full re-litigation on compliance of all processes used to satisfy Public Policy Requirements, including PJM's State Agreement Approach because it addresses state Public Policy Requirements.[639] Pennsylvania Commission argues that the Commission should amend Order No. 1920 to either remove this compliance requirement, explicitly limit it to processes used for Long-Term Regional Transmission Planning, or to clarify that PJM's State Agreement Approach does not interfere with Long-Term Regional Transmission Planning and therefore would not be subject to re-litigation.[640]

207. Similarly, PJM States request that the Commission clarify that PJM's State Agreement Approach does not conflict with Order No. 1920, and that states within PJM can continue to pursue public policies through the voluntary election of the State Agreement Approach in its current form.[641] Pennsylvania Commission also supports and adopts the clarification request of PJM States.[642]

208. PIOs argue that existing Order No. 1000 regional transmission planning processes that plan for reliability or economic transmission needs are unjust, unreasonable, and unduly discriminatory, and they request rehearing of various aspects of Order No. 1920 to ensure that these existing processes complement Long-Term Regional Transmission Planning rather than conflict with and undermine it.[643] Citing a number of statements in Order No. 1920, PIOs contend that these existing regional transmission planning processes threaten the reliability of the transmission system, fail to build transmission infrastructure necessary to meet regional transmission needs over the long term, and instead invest in transmission facilities addressing narrower, shorter-term needs, which ultimately leads to transmission customers paying unjust and unreasonable rates.[644] PIOs contend that evidence in the record demonstrates that failing to address the ''systemic inadequacies'' of existing regional

[631] *Id.* P 1071.

[632] *Id.* (citation omitted).

[633] Large Public Power Rehearing Request at 4–6 (quoting Order No. 1920, 187 FERC ¶ 61,068 at PP 242–243).

[634] *Id.* at 6–9.

[635] *Id.* at 4, 6, 9.

[636] *Id.* at 7.

[637] Pennsylvania Commission Rehearing Request at 2.

[638] Order No. 1920, 187 FERC ¶ 61,068 at PP 252, 256; *see* Pennsylvania Commission Rehearing Request at 2.

[639] Pennsylvania Commission Rehearing Request at 2–3 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 243).

[640] *Id.*

[641] PJM States Rehearing Request at 6–7.

[642] Pennsylvania Commission Rehearing Request at 1.

[643] *See generally* PIOs Rehearing Request at 16–25.

[644] *Id.* at 16–18.

transmission planning processes or aligning them with Long-Term Regional Transmission Planning will perpetuate unjust and unreasonable rates.[645]

209. PIOs therefore request that the Commission amend Order No. 1920 in three ways. First, PIOs argue that the Commission should require transmission providers either to conduct a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs through a combined process or to align the methods of all regional transmission planning processes, including Long-Term Regional Transmission Planning.[646] Second, PIOs argue that the Commission should delineate clear boundaries between and align the timing of Long-Term Regional Transmission Planning and existing processes, such that transmission providers would address only the limited regional transmission needs that cannot be reasonably anticipated and cannot be addressed during a Long-Term Regional Transmission Planning cycle. Otherwise, PIOs contend, these processes all would identify transmission facilities over the same planning periods despite different underlying assumptions, benefits assessments, and cost allocation.[647] Third, PIOs argue that the Commission should require Long-Term Regional Transmission Planning and existing processes to use the same ''base case'' embodying transmission providers' best assessment of future system conditions. Otherwise, PIOs contend, transmission providers ultimately may identify redundant transmission facilities, fail to identify more efficient or cost-effective Long-Term Regional Transmission Facilities, or be motivated to undermine Long-Term Regional Transmission Planning in favor of existing processes.[648]

3. Commission Determination

210. We decline to grant the clarification sought by Large Public Power that the Commission will presume the existing regional transmission planning and cost allocation processes that transmission providers use to consider transmission needs driven by Public Policy Requirements to be just and reasonable. We disagree with Large Public Power that Order No. 1920 was unclear as to how the Commission will evaluate any proposals transmission providers may make in their compliance filings 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. We also disagree with the Pennsylvania Commission that the Commission failed to engage in reasoned decision making. The Commission stated clearly in Order No. 1920, and we continue to find, that, while transmission providers may propose to retain existing Order No. 1000 regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements, transmission providers that do so 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 Order No. 1920.[649] In other words, the Commission will not presume the existing regional transmission planning and cost allocation processes used to consider transmission needs driven solely by Public Policy Requirements are just and reasonable.

211. We also disagree with Large Public Power's argument that the Commission did not justify the differential treatment of regional transmission planning processes that consider transmission needs driven by Public Policy Requirements compared to those that plan for reliability or economic transmission needs. The Commission found that conducting Long-Term Regional Transmission Planning as set forth in Order No. 1920 is sufficient to comply with the Order No. 1000 requirement to consider Public Policy Requirements in the regional transmission planning process. In other words, Long-Term Regional Transmission Planning may subsume the purpose of existing regional transmission planning and cost allocation processes used to consider transmission needs driven by Public Policy Requirements. Given that potential, it is necessary and appropriate to require transmission providers to demonstrate that continued use of Order No. 1000 processes to consider transmission needs driven by Public Policy Requirements does not interfere with or otherwise undermine Long-Term Regional Transmission Planning under Order No. 1920. We also note that Order No. 1920 allows 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, through a combined process, and that transmission providers proposing to address all of these transmission needs in a single regional transmission planning process must demonstrate that the combined 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 Order No. 1920, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order No. 1000 and Order No. 1920.[650]

212. Similarly, we disagree with the Pennsylvania Commission that this requirement is inconsistent with the Commission's statements that, except for Long-Term Regional Transmission Planning, Order No. 1920 will not ''otherwise disturb[ ] the regional transmission planning structure required by Order No. 1000'' or ''inadvertently cause the re-litigation of aspects of those existing processes.'' [651] That said, we appreciate the Pennsylvania Commission's concern that Order No. 1920 requires re-litigation of PJM's State Agreement Approach and its request that the Commission limit the requirement to processes used for Long-Term Regional Transmission Planning. We also recognize PJM States' request for clarification that PJM's State Agreement Approach does not interfere or conflict with Long-Term Regional Transmission Planning. As the Commission explained in Order No. 1920, this requirement does not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process, and transmission providers will be deemed to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set forth in Order No. 1920.[652] Thus, Order No. 1920 allows transmission providers to propose in their Order No. 1920 compliance filings to continue using some or all aspects of the existing Order No. 1000 regional transmission planning and cost allocation processes that they use to consider transmission needs

[645] *Id.* at 20.

[646] *Id.* at 21–23.

[647] *Id.* at 23–24.

[648] *Id.* at 24–25.

[649] Order No. 1920, 187 FERC ¶ 61,068 at P 243; *see also id.* P 240 (declining to pre-judge whether any existing regional transmission planning processes meet the requirements of Order No. 1920).

[650] *Id.* P 244.

[651] *Id.* PP 252, 256; *see* Pennsylvania Commission Rehearing Request at 2–3.

[652] Order No. 1920, 187 FERC ¶ 61,068 at P 242.

driven by Public Policy Requirements, if they so choose. But the Commission held that transmission providers nevertheless must comply with the Long-Term Regional Transmission Planning requirements set forth in Order No. 1920 and that continued use of existing Order No. 1000 regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements alone is insufficient to comply with Order No. 1920. Stated differently, transmission providers that wish to continue to use some or all of their existing Order No. 1000 regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that the continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in Order No. 1920.[653]

213. With respect to PJM's State Agreement Approach specifically, we note that it is separate and apart from PJM's compliance with the Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements.[654] Therefore, PJM's State Agreement Approach is unaffected by Order No. 1920's requirement to justify continued use of regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements. In response to PJM States and Pennsylvania Commission, we note that Order No. 1920 does not prohibit PJM from continuing to use its existing State Agreement Approach. If the Relevant State Entities in PJM agree to rely on PJM's existing State Agreement Approach as an Order No. 1920 State Agreement Process that applies to selected Long-Term Regional Transmission Facilities, and PJM agrees, PJM must propose and demonstrate on compliance that its State Agreement Approach complies with all of the State Agreement Process requirements set forth in Order No. 1920.

214. We also disagree with PIOs' rehearing arguments related to existing regional transmission planning processes that plan for reliability and economic needs and the relationship of these processes to Long-Term Regional Transmission Planning. First, we decline PIOs' request that we require transmission providers to conduct a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs through a combined process. We continue to find that transmission providers may propose on compliance such a combined process, but we do not require that transmission providers do so because the difficulty of transitioning to this kind of combined regional transmission planning process may outweigh any potential benefits of requiring such a process.[655]

215. Furthermore, we find that requiring transmission providers to use a combined process to plan for shorter-term reliability and economic transmission needs and Long-Term Transmission Needs is unnecessary to address the deficiencies in existing regional transmission planning and cost allocation requirements that the Commission identified in Order No. 1920. Specifically, the Commission found that existing 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.[656] Because we find that Order No. 1920's Long-Term Regional Transmission Planning and cost allocation requirements adequately remedy these deficiencies, we decline to impose the additional requirements that PIOs suggest.

216. Second, we find premature PIOs' arguments as to the need to align methods and timing between existing regional transmission planning processes and Long-Term Regional Transmission Planning. In Order No. 1920, the Commission required transmission providers to explain how Long-Term Regional Transmission Planning will interact with existing regional transmission planning processes to plan for transmission needs driven by reliability concerns or economic considerations, including their timing and the potential that Long-Term Regional Transmission Facilities may displace transmission facilities that are under consideration in those processes.[657] The Commission will evaluate the interaction between these processes on compliance and address any potential issues with this interaction in the orders on transmission providers' compliance filings.

217. Third, we disagree with PIOs as to the necessity of requiring that transmission providers use the same ''base case'' in existing regional transmission planning and in Long-Term Regional Transmission Planning. The Commission neither proposed such a requirement in the NOPR nor adopted one in Order No. 1920, and we are not persuaded to adopt PIOs' suggestion in this order. However, we note that nothing in Order No. 1920 precludes transmission providers from using the same base case in existing regional transmission planning and in Long-Term Regional Transmission Planning if they so choose.

B. Long-Term Scenarios Requirements

1. Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs

a. Order No. 1920 Requirements

218. Order No. 1920 required transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, which is defined as a multi-step process to: (1) identify Long-Term Transmission Needs; (2) identify transmission facilities that meet such needs; (3) measure the benefits of those transmission facilities; and (4) evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.[658] Order No. 1920 defined Long-Term Transmission Needs as ''transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors.''[659]

219. Order No. 1920 generally addressed the identification of Long-Term Transmission Needs and the measurement of the benefits of Long-Term Regional Transmission Facilities

[653] *Id.* P 243.

[654] *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, at P 142 (2013) (''We find PJM's proposed State Agreement Approach is not needed for PJM to comply with the provisions of Order No. 1000 addressing transmission needs driven by public policy requirements. PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 . . . . Accordingly, the Commission need not find that the State Agreement Approach and corresponding cost allocation method comply with Order No. 1000.'').

[655] Order No. 1920, 187 FERC ¶ 61,068 at P 245.

[656] *Id.* P 114.

[657] *Id.* PP 1071–1073.

[658] *Id.* P 224.

[659] *Id.* PP 39, 299.

separately.[660] The Commission stated, however, that transmission providers ''must use [the seven required benefits] to help to inform their identification of Long-Term Transmission Needs.'' [661] The Commission provided an example of how transmission providers can use one of the required benefits (the production cost savings benefit, Benefit 3) to help identify Long-Term Transmission Needs.[662]

b. Requests for Rehearing and Clarification

220. PJM requests clarification that the Commission did not intend to require transmission providers to use any of the seven benefits outlined in Order No. 1920 to help inform the identification of Long-Term Transmission Needs. If the Commission did intend to require transmission providers to use the set of seven required benefits to help inform the identification of Long-Term Transmission Needs, PJM requests that the Commission grant rehearing, either to eliminate this requirement or to provide transmission providers with flexibility as to this requirement to accommodate regional differences. PJM asserts that Order No. 1920 contains only one discussion of a requirement for transmission providers to use the seven required benefits to help inform their identification of Long-Term Transmission Needs, and, as such, PJM questions whether the Commission intended to impose this requirement.[663] PJM further asserts that the Commission offered only one hypothetical example of how one of these seven benefits might help inform the identification of Long-Term Transmission Needs, and PJM argues that the Commission did not provide any evidence, let alone substantial evidence, to demonstrate why transmission providers should be required to use the seven benefits to inform the identification of Long-Term Transmission Needs.[664] PJM further claims that requiring the use of all seven benefits outlined in Order No. 1920 to help inform the identification of Long-Term Transmission Needs is inconsistent with PJM's sponsorship model because, in such a model, transmission developers propose transmission facilities after and in response to identified transmission needs, such that using the benefits of such transmission facilities to identify transmission needs is circular.[665] PJM also asserts that the NOPR did not provide notice of the requirement that transmission providers use the seven benefits to help inform the identification of Long-Term Transmission Needs, and PJM therefore lacked opportunity to provide comments as to why the requirement is inappropriate for the PJM region.[666]

221. SERTP Sponsors argue that Order No. 1920 defines Long-Term Transmission Needs in a circular fashion by describing them as ''transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final rule, running scenarios and considering the enumerated categories of factors,'' [667] but also requiring that the seven required benefits should inform the identification of Long-Term Transmission Needs.[668] SERTP Sponsors claim that this creates a potential chicken-or-egg conundrum, because Long-Term Transmission Needs are driven by factors and must be identified before the use and measurement of the seven required benefits to evaluate Long-Term Regional Transmission Facilities.[669]

222. PIOs request three clarifications related to the requirement that transmission providers use the seven benefits to help to inform the identification of Long-Term Transmission Needs.[670] First, PIOs request that the Commission clarify what ''help to inform'' means in this context, in order to avoid an outcome in which the seven benefits are only considered superficially rather than as meaningful determinants of Long-Term Transmission Needs. Second, PIOs request that the Commission clarify that transmission providers may not identify Long-Term Transmission Needs solely on the basis of one of the Order No. 1000 ''silos,'' *e.g.,* reliability. PIOs claim that, if a transmission provider were to identify Long-Term Transmission Needs solely based on reliability, for example, and then use the seven required benefits only to compare potential solutions, the resulting set of needs would be incomplete, and the resulting solutions would be inefficient. Third, PIOs request clarification that the requirement to use the seven required benefits to help identify Long-Term Transmission Needs applies equally to transmission providers that use a competitive bidding process and to those that use a sponsorship model. Regarding the sponsorship model in particular, PIOs also request clarification as to how the Commission envisions the process by which transmission providers could use the seven required benefits to help identify needs, without these needs being so granular that the transmission provider has effectively defined a specific project.[671]

c. Commission Determination

223. We agree with certain of the rehearing arguments raised by PJM and SERTP Sponsors and therefore we set aside the requirement for transmission providers to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs. Specifically, we find that PJM and SERTP Sponsors highlight potential challenges and difficulty transmission providers may have in implementing this requirement. As further explained below, although we find that it is appropriate to set this requirement aside, we clarify and emphasize that the identification of Long-Term Transmission Needs should rely on economic and reliability drivers.

224. In requiring transmission providers to use the set of seven required benefits to help to inform their identification of Long-Term Transmission Needs, the Commission intended in Order No. 1920 to ensure that transmission providers would use their experience evaluating both the reliability and economic benefits of transmission facilities—as reflected in the seven required benefits—and technical expertise assessing the transmission system to identify whether there are reliability issues or opportunities to relieve constraints that could be resolved through Long-Term Regional Transmission Facilities identified through Long-Term Regional Transmission Planning. Upon further consideration, we find that Order No. 1920's Long-Term Regional Transmission Planning requirements, including the requirements to develop Long-Term Scenarios using the

[660] *E.g., id.* P 224 (describing these two requirements as separate steps).

[661] *Id.* PP 301, 719; *see id.* P 667 n.1485, P 859 n.1910.

[662] *Id.* P 301 (''[W]hen 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.'').

[663] PJM Rehearing Request at 24–26 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 301).

[664] *Id.* at 25.

[665] *Id.* at 25–26.

[666] *Id.* at 25 n.103.

[667] SERTP Sponsors Rehearing Request at 11 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 39).

[668] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 719).

[669] *Id.*

[670] PIOs Rehearing Request at 59 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 301, 719).

[671] *Id.* at 59–60.

minimum required Factor Categories,[672] to use the minimum required transmission planning horizon,[673] and to develop Long-Term Scenarios that are plausible and diverse,[674] taken together, will ensure that transmission providers identify Long-Term Transmission Needs.

225. Thus, we are clarifying here that the categories of factors will help transmission providers identify Long-Term Transmission Needs, consistent with the Commission's statements in Order No. 1920.[675] Potential Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs, as identified by the Long-Term Scenarios and sensitivities, will then be evaluated for their economic and reliability benefits, which will ensure that Long-Term Regional Transmission Planning leads to transmission solutions that more efficiently or cost-effectively address reliability and economic transmission needs over the appropriate transmission planning horizon.[676]

226. Finally, because we are setting aside the requirement for transmission providers to use the set of seven required benefits to help inform their identification of Long-Term Transmission Needs, we find moot PIOs' request for clarification concerning this requirement.

2. Transmission Planning Horizon

a. Order No. 1920 Requirements

227. In Order No. 1920, the Commission required transmission providers in each transmission planning region to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. The Commission defined 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.[677] The Commission defined best available data inputs as data inputs that are timely, developed using best practices and diverse and expert perspectives, 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.[678]

228. The Commission clarified 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.[679] The Commission explained that requiring a transmission planning horizon of not less than 20 years strikes a balance. On the one hand, the Commission stated, 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 and allows sufficient time to identify, plan, obtain siting and permitting approval for, and construct more efficient or cost-effective Long-Term Regional Transmission Facilities. On the other hand, the Commission found that there may be sufficient uncertainty regarding system conditions and transmission needs beyond a 20-year transmission planning horizon such that it may be challenging for transmission providers to forecast Long-Term Transmission Needs across that time period.[680]

229. In adopting the minimum 20-year transmission planning horizon requirement in Order No. 1920, the Commission disagreed that a 20-year transmission planning horizon could result in Long-Term Regional Transmission Planning based on speculative transmission needs. The Commission explained that the Long-Term Regional Transmission Planning requirements adopted in Order No. 1920 are designed to avoid over-building transmission in response to speculative transmission needs through a series of tools and safeguards, which include the requirement that transmission providers reevaluate Long-Term Regional Transmission Facilities in certain circumstances.[681]

230. The Commission also disagreed with requests that it adopt a shorter transmission planning horizon, reasoning that a shorter planning horizon would fail to sufficiently capture Long-Term Transmission Needs given that some drivers of such needs extend up to 20 years into the future. The Commission added that a shorter minimum transmission planning horizon might 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.[682]

b. Requests for Rehearing and Clarification

231. Alabama Commission, Ohio Commission Federal Advocate, and Dominion seek rehearing of Order No. 1920's requirement that transmission providers in each transmission planning region develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.[683]

232. Dominion contends that Order No. 1920 is arbitrary and capricious because the Commission failed to address Dominion's concerns regarding the use of a 20-year transmission planning horizon.[684] Dominion asserts that the Commission failed to address its NOPR comments, which argued that a 20-year transmission planning horizon runs the risk of essentially implementing a ''transmission Integrated Resource Plan'' that mandates potentially speculative transmission projects. Dominion avers that integrated resource plans are snapshots in time that show potential pathways for meeting future needs and are not

[672] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

[673] *Id.* P 344.

[674] *Id.* P 414.

[675] *See id.* P 299 (stating that ''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''); *id.* P 300 (stating that ''Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000,'' which include both reliability and economic considerations).

[676] We note that this understanding that potential Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs are evaluated for both reliability and economic benefits is consistent with the Commission's determination in Order No. 1920 that, while transmission providers have significant flexibility to determine a regionally appropriate *ex ante* cost allocation, such cost allocation may not be based on a siloed approach that assumes Long-Term Regional Transmission Planning addresses only reliability or only economic needs. However, as also noted below, transmission providers and Relevant State Entities have broad flexibility to recognize the different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits. *See infra* General Benefits Requirements Related to Cost Allocation section.

[677] Order No. 1920, 187 FERC ¶ 61,068 at P 302.

[678] *Id.* P 633.

[679] *Id.* P 344.

[680] *Id.* P 345.

[681] *Id.* P 348.

[682] *Id.* P 349.

[683] Alabama Commission Rehearing Request at 4; Dominion Rehearing Request at 11–14; Ohio Commission Federal Advocate Rehearing Request at 20–21.

[684] Dominion Rehearing Request at 7, 12–15.

concrete, definitive plans.[685] Dominion states that in its NOPR comments it explained that predicting the future resource mix is challenging and that numerous planning considerations that apply today could change over the next 20 years, which is why Dominion cautioned against requiring transmission providers to make investment and cost allocation decisions based on speculation 20 years into the future.[686]

233. According to Dominion, its NOPR comments also asserted that a 20-year transmission planning horizon requires using less reliable assumptions, which can lead to stranded or misallocated costs,[687] especially because cost allocation under Order No. 1920 could occur much earlier than before.[688] Dominion argues that planning further into the future decreases certainty, likely has diminishing returns, and requires transmission providers to deploy personnel with scarce planning expertise—a highly valuable resource—who could be used more efficiently by planning for likelier scenarios.[689]

234. Further, Dominion argues that because Order No. 1920 would not necessarily permit reevaluation in certain circumstances that could render a transmission project unnecessary—*e.g.,* where changes in technology or load growth obviate the need for a project in a particular location—the reevaluation process is insufficient to address concerns regarding the speculative nature of a 20-year planning horizon.[690]

235. Dominion also argues that the Commission arbitrarily dismissed its requests for flexibility to adopt a timeline that is suited to a particular transmission planning region to reduce the risk of selection of transmission projects that may not actually be needed.[691] Dominion states that, if the Commission must prescribe a minimum transmission planning horizon, it would be more reasonable to continue allowing PJM/Dominion Energy Virginia to use a 15-year forecast horizon, which strikes a balance between long-term needs and avoiding speculative projects, and to continue allowing South Carolina Regional Transmission Planning/ Dominion Energy South Carolina to use a 10-year transmission planning horizon. Such transmission planning horizons, Dominion claims, would be more tailored to the transmission planning regions' needs.[692]

236. Ohio Commission Federal Advocate also asserts that the Commission acted arbitrarily and capriciously and violated the consumer protection provisions of the FPA by adopting the 20-year transmission planning horizon requirement. Ohio Commission Federal Advocate argues that a 20-year transmission planning horizon puts transmission planners in the ''impossible position'' of having to predict the resource mix and location of resources 20 years in the future and will lead to inefficient and potentially unnecessary investment decisions.[693] In the alternative to seeking rehearing on the 20-year transmission planning horizon requirement, Ohio Commission Federal Advocate requests that the Commission clarify that the 20-year planning horizon should be informational only and should not be relied upon for investment decisions until the future can be better ascertained.[694] Similarly, Alabama Commission contends that a 20-year transmission planning horizon is likely to produce speculative outputs that lack sufficient basis for actionable planning decisions and that action on these outputs should be determined at the state level to avoid costly transmission facilities that are not actually needed.[695]

i. Commission Determination

237. We sustain the requirement that transmission providers in each transmission planning region develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. The Commission's adoption of a 20-year transmission planning horizon was reasonable and supported by record evidence,[696] and the Commission did not disregard arguments to the contrary. As the Commission explained in Order No. 1920, a transmission planning horizon of less than 20 years would fail to sufficiently capture Long-Term Transmission Needs given that drivers of such needs can extend up to 20 years into the future, such as state laws that include requirements to be met 15 to 20 years in the future.[697] In addition, 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.[698]

238. Moreover, we continue to find that 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.[699] We therefore are not convinced by arguments that the Commission should have adopted a minimum transmission planning horizon shorter than 20 years.

239. We disagree with arguments that the minimum 20-year transmission planning horizon could result in the selection of speculative transmission projects or will lead to inefficient and potentially unnecessary investment decisions,[700] including Dominion's related argument that a 20-year transmission planning horizon runs the risk of ''essentially implementing a transmission Integrated Resource Plan [] that mandates investments in potentially speculative transmission projects'' or may result in imprecision and could lead to stranded or misallocated costs.[701] As the Commission found in Order No. 1920, the Long-Term Regional Transmission Planning requirements include tools and safeguards designed to avoid over-building transmission in response to speculative transmission needs.[702] These tools and safeguards include: (1) the requirement that transmission providers develop (and periodically update) multiple plausible and diverse Long-Term Scenarios based upon best available data; (2) transmission providers' flexibility to develop evaluation processes, including selection criteria, that will enable them to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs

[685] *Id.* at 13–14 (citing Dominion NOPR Initial Comments at 18–19).

[686] *Id.* at 14 (citing Dominion NOPR Initial Comments at 20).

[687] *Id.* (citing Dominion NOPR Initial Comments at 20).

[688] *Id.*

[689] *Id.* at 15.

[690] *Id.* at 16–18.

[691] *Id.* at 15.

[692] *Id.* at 12–13, 16.

[693] Ohio Commission Federal Advocate Rehearing Request at 20–21.

[694] *Id.* at 21.

[695] Alabama Commission Rehearing Request at 4.

[696] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 309–318 (describing support for a transmission planning horizon of at least 20 years).

[697] *Id.* P 349.

[698] *Id.* P 345; *see also id.* P 312 (describing arguments of commenters whose comments supported a 20-year transmission planning horizon).

[699] *Id.* P 349.

[700] Alabama Commission Rehearing Request at 4; Dominion Rehearing Request at 11–15; Ohio Commission Rehearing Request at 20–21.

[701] Dominion Rehearing Request at 13–14.

[702] Order No. 1920, 187 FERC ¶ 61,068 at P 348.

over time without over-building transmission facilities; and (3) the lack of a selection mandate.[703] We continue to find that, by facilitating regional transmission planning that accounts for a range of potential futures, Order No. 1920 ensures that transmission providers will be able to manage uncertainty, which, in turn, mitigates the risk of speculative transmission development.[704]

240. Although Dominion argues that the reevaluation process is insufficient to address concerns that a 20-year transmission planning horizon could lead to the selection of speculative transmission projects,[705] Dominion does not demonstrate how Order No. 1920's other tools and safeguards beyond the reevaluation requirement are individually or collectively insufficient to prevent over-building transmission in response to speculative transmission needs.[706] Moreover, robust scenario-planning allows transmission providers to compare the costs and benefits of Long-Term Regional Transmission Facilities under different future conditions, which informs selection and consequently helps to mitigate uncertainty.

241. In addition, as discussed later,[707] we also clarify that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to states' laws, policies, and regulations in transmission planning assumptions, which will ensure that such factors are effectively accounted for in the development of Long-Term Scenarios. We believe this clarification mitigates Ohio Commission Federal Advocate's concerns that the 20-year transmission planning horizon could result in unnecessary investment.[708] With this clarification, Order No. 1920 provides transmission providers with the tools and safeguards that they need to manage uncertainty and mitigate the risk of speculative regional transmission development while preserving the benefits of Long-Term Regional Transmission Planning.

242. For the same reason, we are unpersuaded by Alabama Commission's related argument that action on transmission plans should be determined at the state level to avoid costly transmission facilities that may not be needed. Nonetheless, as further discussed in this order, we clarify Order No. 1920 to require transmission providers to include and consider the perspective of Relevant State Entities in multiple ways, including: (1) to consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios; (2) to include any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities agree to in the transmittal or as an attachment to their compliance filings; (3) to consult with Relevant State Entities (a) prior to amending the *ex ante* Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) agreed to by Relevant State Entities or (b) if Relevant State Entities seek for a transmission provider to amend the method on file; (4) to develop a reasonable number of additional scenarios, when requested by Relevant State Entities, for the purposes of informing the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es); and (5) to make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of the allocated costs, by zone (*i.e.,* by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of the benefits imputed to each zone, as such benefits can be reasonably estimated, when a cost allocation method is agreed upon under a State Agreement Process or, if no State Agreement Process is used, at the time the transmission provider selects the Long-Term Regional Transmission Facility. These additional measures to involve states will resolve Alabama Commission's concern and prevent costly transmission facilities that are not actually needed from being constructed.

243. As to another argument raised by Alabama Commission, which we interpret to argue that Long-Term Regional Transmission Planning should serve only to inform other transmission planning processes, we continue to find that remedying the deficiencies in the Commission's existing regional transmission planning requirements requires that transmission providers adopt the requirements herein, which will allow them to identify and have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs.[709]

244. We disagree with Dominion's argument that the Commission failed to address commenters' request for flexibility regarding the length of the minimum transmission planning horizon. The Commission has already justified its decision not to adopt a shorter transmission planning horizon, reasoning that a planning horizon of less than 20 years would be insufficient to capture Long-Term Transmission Needs, develop and construct Long-Term Regional Transmission Facilities with long lead-time requirements, and compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.[710] The Commission explained why providing transmission providers with flexibility to choose a shorter transmission planning horizon would limit transmission providers' ability to adequately plan for Long-Term Transmission Needs and perpetuate the status quo, thus failing to address the deficiencies that the Commission identified in its existing regional transmission planning and cost allocation requirements.[711] Moreover, in adopting the 20-year minimum transmission planning horizon, the Commission struck a balance between, on the one hand, providing transmission providers with sufficient time to proactively identify Long-Term Transmission Needs and ultimately construct more efficient or cost-effective Long-Term Regional Transmission Facilities to meet those needs, and, on the other hand, avoiding uncertainty regarding system conditions and

[703] *Id.* P 231.

[704] *Id.* P 229.

[705] Dominion Rehearing Request at 16–18.

[706] For example, Order No. 1920 requires transmission providers to develop (and periodically update) multiple plausible and diverse Long-Term Scenarios based upon best available data, provides transmission providers with flexibility to develop evaluation processes, including selection criteria, that will enable them to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities, and lacks a selection mandate.

[707] *Infra* Stakeholder Process and Transparency section.

[708] We also note that the transparency requirements adopted herein, *see infra* Evaluation and Selection of Long-Term Regional Transmission Facilities, will provide states with additional insight into the efficiency and cost-effectiveness of any Long-Term Regional Transmission Facilities that transmission providers select.

[709] Order No. 1920, 187 FERC ¶ 61,068 at P 914.

[710] *Id.* P 349.

[711] *See, e.g., id.* PP 115–116 (finding that, under the status quo, most transmission planning regions do not plan beyond a 10-year transmission planning horizon, which 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 and fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide).

transmission needs beyond a 20-year horizon.[712]

245. Finally, we reiterate that, in this order, the Commission clarifies Order No. 1920 to increase the states' involvement in the Long-Term Transmission Planning Process to provide them with a greater role in determining Long-Term Transmission Needs, and ensuring that they are able to provide input into the method used to allocate the costs of Long-Term Regional Transmission Facilities.

246. For these reasons, we reject Dominion's request that the Commission allow PJM/Dominion Energy Virginia to continue to use a 15-year transmission planning horizon and South Carolina Regional Transmission Planning/Dominion Energy South Carolina to continue to use a 10-year transmission planning horizon.[713] Likewise, for these same reasons, we decline Ohio Commission Federal Advocate's request that the Commission clarify that Long-Term Scenarios resulting from a 20-year transmission planning horizon will be used for informational purposes only.

247. Further, we find unpersuasive Ohio Commission Federal Advocate's allegation that the Commission contravened the consumer-protection requirements of the FPA by adopting a 20-year minimum transmission planning horizon.[714] Ohio Commission Federal Advocate does not state how the 20-year minimum transmission planning horizon contravenes the FPA nor does it specify which requirements of the FPA the Commission allegedly transgressed by adopting the 20-year minimum transmission planning horizon requirement. To the extent that Ohio Commission Federal Advocate is claiming that the 20-year minimum transmission planning horizon requirement will result in unjust and unreasonable rates, as discussed above, we have provided a number of flexibilities to increase the states' involvement in Long-Term Regional Transmission Planning and to ensure that there is a significant degree of transparency in Long-Term Regional Transmission Planning, both of which will ensure that rates are just and reasonable. Recognizing these additional flexibilities, we continue to find the required 20-year minimum transmission planning horizon is integral to the requirement that transmission providers conduct long-term, forward-looking, and more comprehensive regional transmission planning.[715] The Commission found that such a requirement is necessary to remedy the deficiencies that it identified in its existing regional transmission planning and cost allocation requirements[716] and will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to Long-Term Transmission Needs, which will help ensure just and reasonable rates.[717]

3. Frequency of Long-Term Scenario Revisions

a. Order No. 1920 Requirements

248. In Order No. 1920, the Commission modified the NOPR proposal and required 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,[718] rather than at least every three years as the NOPR proposed.[719] The Commission explained that, 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.[720] The Commission clarified that a Long-Term Regional Transmission Planning cycle, which begins with the development of Long-Term Scenarios using best available data inputs,[721] and 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, must conclude no later than five years after the date it began.[722] Transmission providers must complete these steps of the Long-Term Regional Transmission Planning cycle, including selection decisions, no later than three years from the date that the Long-Term Regional Transmission Planning cycle began.[723]

249. The Commission stated that nothing in Order No. 1920 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.[724] However, the Commission explained that, 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.[725]

250. The Commission found that, while three years provides sufficient time for transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle,[726] requiring the Long-Term Regional Transmission Planning cycle to repeat at three-year intervals could be administratively burdensome and the benefit of updating Long-Term Scenarios every three years may not outweigh those additional burdens.[727] Thus, the Commission found 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 between various benefits and burdens.[728] Order No. 1920 required that transmission providers conclude one Long-Term Regional Transmission Planning cycle before developing Long-Term Scenarios at the beginning of the next Long-Term Regional Transmission Planning cycle.[729]

251. Order No. 1920 also required transmission providers to designate a point in the evaluation process at which they will decide to either select or not select the relevant Long-Term Regional Transmission Facility (or portfolio of such Facilities) along with a point in time or action that concludes a Long-Term Regional Transmission Planning cycle.[730] The Commission further stated that transmission providers may propose on compliance to conduct

[712] *Id.* P 345.

[713] *See* Dominion Rehearing Request at 12–13, 16.

[714] *See* Ohio Commission Federal Advocate Rehearing Request at 20.

[715] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 345, 349.

[716] *Id.* P 134.

[717] *See id.* PP 345, 349.

[718] *Id.* P 377.

[719] NOPR, 179 FERC ¶ 61,028 at P 97.

[720] Order No. 1920, 187 FERC ¶ 61,068 at P 377.

[721] 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 for previously developed Long-Term Scenarios. *Id.*

[722] *Id.* P 378.

[723] *Id.* P 379.

[724] *Id.* P 379 n.873.

[725] *Id.*

[726] Order No. 1920, 187 FERC ¶ 61,068 at P 379 (citations omitted).

[727] *Id.* (citations omitted).

[728] *Id.*

[729] *Id.* P 381.

[730] *Id.*

Long-Term Regional Transmission Planning more frequently than every five years.[731]

b. Requests for Rehearing and Clarification

252. PIOs request rehearing of the Commission's decision to extend the Long-Term Regional Transmission Planning Cycle from three years to five years. They request that the Commission reduce the Long-Term Regional Transmission Planning cycle to three years.[732] PIOs argue that the Commission's decision to extend the Long-Term Regional Transmission Planning cycle from three years, as it proposed in the NOPR, to five years lacked support in the record, was not based on the Commission's findings, and was arbitrary and capricious given the urgency of the problem.[733] PIOs assert that the faster transmission drivers change, the more frequently Long-Term Scenarios should be updated.[734] PIOs contend that, in decreasing the frequency of Long-Term Regional Transmission Planning cycles, the Commission disregarded evidence that transmission drivers—*e.g.,* reliability concerns, demand, interconnection request capacity—have changed at an accelerating pace, since the issuance of the NOPR.[735]

253. PIOs aver that under Order No. 1920, transmission providers complete the entire substance of the planning cycle projects in the first three years, followed by a ''fallow period'' for up to two years.[736] This structure, PIOs argue, fails to alleviate the purported administrative burdens associated with the NOPR's three-year proposal and undermines Order No. 1920's essential purpose of requiring transmission providers to identify and address rapidly-shifting and critical regional transmission needs with urgency.[737] PIOs assert that it is illogical for the Commission to claim that transmission providers need two additional years at the end of each cycle to update model inputs in preparation for the next transmission planning cycle when they initially assembled that same information, from scratch, in three years.[738]

254. In support of their request that the Commission grant rehearing and adopt the NOPR's proposed three-year transmission planning cycle, PIOs also assert that the structure of the five-year planning structure is unclear. PIOs argue that Order No. 1920 nearly contradicts itself by stating that transmission providers must ''determine whether to select Long-Term Regional Transmission Facilities no later than three years'' after the cycle begins and then adding that ''nothing in this final rule prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three'' of the cycle and before the next cycle begins.[739] PIOs argue that, while these and similar statements are facially irreconcilable, they could be harmonized under a reading that would allow transmission providers to make final selection decisions on any Long-Term Regional Transmission Facilities up until the end of the five-year transmission planning cycle as long as they make a selection decision on at least one Long-Term Regional Transmission Facility before the end of year three.[740] According to PIOs, however, such a structure would undermine stakeholder concerns about changes to the planning process that occur mid-stream that would require re-running an analysis and would encourage transmission providers to make decisions when stakeholders are no longer at the table.[741] PIOs request that the Commission grant rehearing and adopt the NOPR's widely supported three-year transmission planning cycle.[742]

255. SERTP Sponsors request clarification as to what Order No. 1920 requires with respect to the inclusion of previously selected Long-Term Regional Transmission Facilities in updated base or reference cases that transmission providers use in the subsequent Long-Term Regional Transmission Planning cycle. SERTP Sponsors claim that Order No. 1920 may be inconsistent on this question because one section of the rule appears to require transmission providers to include such facilities in these updated base or reference cases while another section of the rule appears to provide flexibility on this issue.[743]

c. Commission Determination

256. We sustain the requirement that transmission providers in each transmission planning region reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years.[744] We disagree with PIOs that the decision to extend the Long-Term Regional Transmission Planning cycle from three years to five years lacked support in the record, was not based on the Commission's findings, and was arbitrary and capricious.

257. First, we are not persuaded by PIOs' argument that, by extending the Long-Term Regional Transmission Planning cycle, the Commission acted inconsistently with its findings in Order No. 1920 that transmission needs are changing at an increasingly rapid pace.[745] In Order No. 1920, the Commission addressed the pace at which transmission drivers are changing, finding that transmission providers must reassess and revise their Long-Term Scenarios at least once every five years 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.[746] While transmission needs, and the factors driving those needs, are indeed changing rapidly, PIOs provide insufficient and unconvincing support for their argument that a five-year Long-Term Regional Transmission Planning cycle is incapable of accounting for that pace of change. Further, we underscore that Order No. 1920 provides transmission providers with flexibility to address evolving transmission needs. For instance, nothing in Order No. 1920 prohibits transmission providers from updating the assumptions, inputs, and factors, used to inform Long-Term Scenarios during a Long-Term Regional Transmission Planning cycle,[747] and, to the extent that transmission providers believe that a shorter Long-Term Regional Transmission Planning cycle is necessary to account for the pace of change, they may propose on compliance to conduct Long-Term

[731] *Id.* P 384.

[732] PIOs Rehearing Request at 9–15.

[733] *Id.* at 6 (citations omitted).

[734] *Id.* at 10–11.

[735] *Id.* at 9–11 (citations omitted).

[736] *Id.* at 11 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 378–379).

[737] *Id.* at 12.

[738] *Id.* at 12–13.

[739] *Id.* at 13 (quoting Order No. 1920, 187 FERC ¶ 61,068 at PP 379, 381).

[740] *Id.* at 14.

[741] *Id.* at 13–14.

[742] *Id.* at 15. PIOs also argue that, for the small minority of entities that need more initial flexibility beyond the one-year period entities already have to file compliance filings, the Commission could allow for case-by-case extensions. *Id.*

[743] SERTP Sponsors Rehearing Request at 26–27 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 382, 1031).

[744] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 377.

[745] PIOs Rehearing Request at 9–11.

[746] Order No. 1920, 187 FERC ¶ 61,068 at P 380.

[747] *See id.* PP 380–381. We also note that, consistent with Order No. 890's transparency transmission planning principle, Order No. 1920 requires 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. *See id.* P 560 (citing Order No. 890, 118 FERC ¶ 61,119 at P 471).

Regional Transmission Planning more frequently than every five years.[748]

258. Second, the Commission's decision to require that Long-Term Regional Transmission Planning cycles occur at least every five years was guided by comments in the record urging the Commission to address competing priorities, including: (1) ensuring timely identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities; (2) providing transmission providers with sufficient flexibility to address regional differences; and (3) limiting the administrative burdens placed on transmission providers.[749] Order No. 1920's requirement that transmission providers reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years strikes a reasonable balance between those priorities. Further, we disagree with PIOs' assertion that extending the Long-Term Regional Transmission Planning cycle from three years to five years does not ease administrative burdens or improve planning accuracy.[750] In Order No. 1920, the Commission decreased the frequency at which Long-Term Regional Transmission Planning cycles must occur, meaning that transmission providers have the option to develop fewer Long-Term Scenarios over a five-year period than they would have been required to develop under the NOPR proposal, thus decreasing the administrative burden associated with updating the Long-Term Scenarios that form the basis for Long-Term Regional Planning during each planning cycle.

259. Third, we are not persuaded by PIOs' argument that the structure of the Long-Term Regional Transmission Planning cycle is unclear or that its implementation will exclude meaningful stakeholder participation.[751] Order No. 1920 requires transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle and make selection decisions no later than three years from the date when the Long-Term Regional Transmission Planning cycle began.[752] To the extent that transmission providers decide to evaluate additional Long-Term Regional Transmission Facilities after year three but before the next Long-Term Regional Transmission Planning cycle begins, Order No. 1920 gives them the flexibility to do so.[753] One possible outcome of this structure is that transmission providers may make selection decisions on additional Long-Term Regional Transmission Facilities until the end of the five-year Long-Term Regional Transmission Planning cycle. But we disagree with PIOs' contention that Order No. 1920 could be read to allow transmission providers to make ''final'' selection decisions on ''*any*'' Long-Term Regional Transmission Facilities until the five-year Long-Term Regional Transmission Planning cycle's end so long as they make a selection decision on at least one Long-Term Regional Transmission Facility before the end of year three.[754]

260. Order No. 1920 requires that transmission providers complete their evaluation and selection processes in the first three years of a Long-Term Regional Transmission Planning cycle, including identifying Long-Term Regional Transmission Facilities that address the Long-Term Transmission Needs that transmission providers identified, estimating the costs and measuring the benefits of those facilities, and making a selection decision on those facilities, including a determination that is sufficiently detailed for stakeholders to understand why particular facilities or portfolios of facilities were selected or not selected.[755] After transmission providers have completed these steps, no later than three years after the beginning of the Long-Term Regional Transmission Planning cycle, transmission providers may select ''*additional*'' Long-Term Regional Transmission Facilities, but they may not deselect any Long-Term Regional Transmission Facilities selected earlier in that Long-Term Regional Transmission Planning cycle.[756]

261. We therefore disagree with PIOs' argument that the five-year structure of the Long-Term Regional Transmission Planning cycle would encourage transmission providers to make planning decisions when stakeholders are ''no longer at the table.'' [757] Such arguments are predicated on a misunderstanding of what Order No. 1920 requires. We emphasize that any Long-Term Regional Transmission Facilities selected after year three of the Long-Term Regional Transmission Planning cycle are selected in the Long-Term Regional Transmission Planning process. Thus, contrary to PIOs' suggestion, the requirements for selecting Long-Term Regional Facilities apply, including the transparency requirements adopted in Order No. 1920, should transmission providers choose to evaluate and select additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle.[758]

262. Finally, we provide clarification to SERTP Sponsors as to the inclusion of previously selected Long-Term Regional Transmission Facilities in the updated base or reference cases that transmission providers will use in subsequent Long-Term Regional Transmission Planning cycles. In most circumstances, we expect that transmission providers will include previously selected Long-Term Regional Transmission Facilities, including those that are not yet in service, in these updated planning models, and we continue to find that doing so will improve the accuracy of Long-Term Regional Transmission Planning.[759] We expect that if transmission providers conclude that previously-selected Long-Term Regional Transmission Facilities are not appropriate to use in a base case, they would provide an explanation to stakeholders who may be relying on the base case in future transmission planning or generator interconnection studies as to why these facilities are not included. Nevertheless, we clarify that Order No. 1920 does not *require* that transmission providers include previously selected Long-Term Regional Transmission Facilities in the planning models that they use in a subsequent Long-Term Regional Transmission Planning cycle, and we continue to find that it is appropriate to provide flexibility to transmission providers on how they update their planning models.[760]

4. Categories of Factors

a. Requirement To Incorporate Categories of Factors

i. Order No. 1920 Requirements

263. In Order No. 1920, the Commission required transmission providers in each transmission planning region to incorporate in the development of Long-Term Scenarios seven specific categories of factors: (1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand;

[748] *See id.* P 384.

[749] *See id.* P 379.

[750] PIOs Rehearing Request at 12–13.

[751] *Id.* at 13–15.

[752] Order No. 1920, 187 FERC ¶ 61,068 at PP 379, 955.

[753] *Id.* P 379 n.873.

[754] PIOs Rehearing Request at 14.

[755] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 955.

[756] *Id.* P 379 n.873.

[757] PIOs Rehearing Request at 14.

[758] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 954.

[759] *See id.* P 382.

[760] *See id.* P 1031.

(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.[761] The Commission found that incorporating these categories of factors in the development of Long-Term Scenarios is necessary because these categories are essential to identifying Long-Term Transmission Needs, and that incorporating them will ensure that transmission providers are accounting for known and identifiable drivers of Long-Term Transmission Needs.[762] The Commission stated that transmission providers may not exclude any of the proposed categories of factors from the development of Long-Term Scenarios because each category of factors includes important drivers of Long-Term Transmission Needs, and that not incorporating all of the categories of factors will increase the likelihood that transmission providers will continue to underestimate or omit certain drivers of Long-Term Transmission Needs.[763]

264. The Commission explained that incorporating a category of factors in the development of Long-Term Scenarios requires transmission providers to 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.[764] The Commission stated that it expects 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.[765] Further, 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.[766]

265. With respect to factors within each category of factors, Order No. 1920 requires that transmission providers account for the factors that they have determined are likely to affect Long-Term Transmission Needs. Order No. 1920 further requires transmission providers, in coordination with stakeholders through an open and transparent process, to determine how each of those factors (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 Long-Term Scenarios but need not account for a factor that they determine is unlikely to affect Long-Term Transmission Needs.[767]

266. The Commission stated that requiring transmission providers to incorporate the seven categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility.[768] The Commission also stated that the final rule does not direct the development of specific transmission facilities because transmission providers retain discretion to determine how specific factors will affect Long-Term Transmission Needs.[769]

ii. Requests for Rehearing and Clarification

267. Arizona Commission argues that Order No. 1920's requirement that transmission providers use a specific set of ''planning criteria,'' *i.e.,* that transmission providers incorporate seven categories of factors in Long-Term Scenarios, is ''simply a way of 'pre-cooking' outcomes.'' [770] Arizona Commission argues that this is inconsistent with the NOPR, which required transmission providers to implement a process, not achieve specific outcomes.[771]

268. SERTP Sponsors request that the Commission clarify or, in the alternative, grant rehearing to specify that Order No. 1920 does not require each factor to have an additive effect on a common assumption because, in their view, such a requirement would be arbitrary and capricious and not supported by substantial evidence.[772] SERTP Sponsors assert that requiring each factor to have an additive effect would undermine transmission providers' discretion over how to account for different factors.[773]

269. Further, SERTP Sponsors argue that the record does not demonstrate that each individual factor will have an additive effect, and a finding to this effect risks overstating the effect of each factor, which would render the resulting scenarios implausible and more likely to misidentify Long-Term Transmission Needs and Facilities.[774]

270. Designated Retail Regulators and Undersigned States request that the Commission grant rehearing on the grounds that the Order No. 1920 requirement to use the seven categories of factors in Long Term Regional Transmission Planning will overvalue transmission benefits and will result in unjust, unreasonable, and unduly discriminatory rates.[775] Designated Retail Regulators and Undersigned States argue that transmission planning assumptions should reflect regional differences, and that requiring transmission providers to develop Long-Term Scenarios that incorporate Order No. 1920's seven categories of factors will result in unjust and unreasonable rates because the categories of factors overlap and may result in double counting.[776] Designated Retail Regulators and Undersigned States also assert that there is insufficient evidence and analysis to conclude that use of the factors will result in cost-effective solutions.[777]

iii. Commission Determination

271. Regarding Arizona Commission's argument that Order No. 1920's requirement that transmission providers incorporate seven categories of factors into their development of Long-Term Scenarios predetermines outcomes in Long-Term Regional Transmission Planning, we reiterate that, in Order No. 1920, as clarified herein, the Commission gives transmission providers the tools necessary to respond to changing factors that drive Long-Term Transmission Needs.[778] As discussed below in further detail,[779] transmission providers must consult with and consider the positions of the Relevant State Entities and any other

[761] *Id.* P 409.
[762] *Id.* P 410.
[763] *Id.* P 411.
[764] *Id.* P 413.
[765] *Id.*
[766] *Id.* P 414.
[767] *Id.* P 415.
[768] *Id.* P 417.
[769] *Id.* P 419.
[770] Arizona Commission Rehearing Request at 18.
[771] *Id.*
[772] SERTP Sponsors Rehearing Request at 12–13.
[773] *Id.* at 13.
[774] *Id.*
[775] Designated Retail Regulators Rehearing Request at 8, 26; Undersigned States Rehearing Request at 8, 26.
[776] Designated Retail Regulators Rehearing Request at 8, 26–29; Undersigned States Rehearing Request at 8, 26–29.
[777] Designated Retail Regulators Rehearing Request at 8; Undersigned States Rehearing Request at 8.
[778] Order No. 1920, 187 FERC ¶ 61,068 at P 233.
[779] *Infra* Stakeholder Process and Transparency section.

entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios. The Commission also explained in both the NOPR and in Order No. 1920 that it is not requiring that transmission providers achieve any particular outcome via Long-Term Regional Transmission Planning,[780] and Order No. 1920 does not mandate selection of any Long-Term Regional Transmission Facilities.[781]

272. In response to SERTP Sponsors' request for clarification, we clarify that Order No. 1920 does not require transmission providers, when determining the assumptions that they will use when developing Long-Term Scenarios where similar factors (or groups of factors) affect a single assumption, to assume that the factors have additive effects on the relevant assumptions. The Commission stated in Order No. 1920 that it expected 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,[782] but we agree with SERTP Sponsors that this may not always be the case, and at times, similar factors may not have an additive effect on assumptions used to develop Long-Term Scenarios. We also acknowledge that factors in different categories of factors may overlap.[783]

273. We clarify that, where factors may have overlapping effects on the planning assumptions, transmission providers must avoid double counting the effect that those factors have on assumptions used to develop Long-Term Scenarios. Specifically, where there is overlap between factors in Factor Categories One through Three and factors in Factor Categories Four through Seven, or a factor could arguably be considered in a Factor Category in the first three categories or the last four categories, transmission providers must incorporate that factor in the appropriate Factor Category in the first three categories.[784] Because Relevant State Entities and their designated representatives will participate in developing Long-Term Scenarios by informing how transmission providers account for the impact of individual factors, we believe that Relevant State Entities, working in concert with transmission providers, will be able to identify and minimize instances where factors overlap. Further, to the extent that factors in Factor Categories One through Three have overlapping effects on planning assumptions, transmission providers must ensure that each Long-Term Scenario accounts for the factors in Factor Categories One through Three without double counting their effects on planning assumptions. Finally, although we agree with SERTP Sponsors that similar factors will not always have an additive effect on assumptions used to develop Long-Term Scenarios, where similar factors do not overlap, we clarify our expectation that similar factors (or groups of factors) affecting certain assumptions used in the development of Long-Term Scenarios will have a combined effect on those assumptions accordingly.

274. In response to SERTP Sponsors' argument that the requirements in Order No. 1920 risk overstating the effect of each factor, which would render the resulting scenarios implausible and more likely to misidentify Long-Term Transmission Needs, we explain that Order No. 1920 addresses this issue by allowing transmission providers to exercise discretion in how they account for each factor, provided that each Long-Term Scenario account for and be consistent with factors in the first three categories of factors.[785] As the Commission noted in Order No. 1920, incorporating a category of factors into the development of Long-Term 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.[786] In addition, the Commission held in Order No. 1920 that transmission providers have the discretion to determine whether specific factors must be accounted for within each category, how to account for specific factors in the development of Long-Term Scenarios, and how to vary the treatment of each category of factors across Long-Term Scenarios, provided that transmission providers assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities that transmission providers have determined are likely to affect Long-Term Transmission Needs are fully met.[787] Finally, we believe that the clarification discussed below will mitigate SERTP Sponsors' concern by ensuring that the effects of factors used to develop Long-Term Scenarios are not overstated.

275. More specifically, Order No. 1920 states that transmission providers must give states and stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate in Long-Term Scenarios, including how specific factors may affect Long-Term Transmission Needs.[788] We clarify below that, when incorporating planning for states' laws, policies, and regulations' into the development of Long-Term Scenarios, transmission providers must consult with and consider the positions of the Relevant State Entities and their designated representatives as to how those requirements will be realized.[789] If, for example, states have laws regarding the future resource mix or decarbonization targets, the assumptions for how the power industry would need to evolve to meet those legal requirements should be developed in close consultation with the Relevant State Entities. We clarify that, for a state that has required integrated resource planning processes, transmission providers should include one of the state's preferred power system trajectories, including both the supply and demand side resource trajectory as appropriate, in each Long-Term Scenario, or include different state-preferred power system trajectories in different Long-Term Scenarios.

276. While we disagree with the rehearing arguments of Designated Retail Regulators and Undersigned States that the Order No. 1920 requirement to use the seven categories

[780] *See, e.g.,* NOPR, 179 FERC ¶ 61,028 at PP 9, 245; Order No. 1920, 187 FERC ¶ 61,068 at PP 232, 266.

[781] Order No. 1920, 187 FERC ¶ 61,068 at PP 1026–1027.

[782] *Id.* P 413.

[783] *Id.* P 440 (''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.''). As another example, a utility commitment in Factor Category Seven would overlap with an integrated resource plan if the utility commitment was incorporated in the development of the integrated resource plan.

[784] For example, if a transmission provider determines that a factor will affect Long-Term Transmission Needs, but the factor could arguably be incorporated in Factor Category Three or Factor Category Seven, the transmission provider must incorporate this factor in Factor Category Three.

[785] It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[786] Order No. 1920, 187 FERC ¶ 61,068 at P 413.

[787] *Id.* P 417.

[788] *Id.* P 528.

[789] *Infra* Stakeholder Process and Transparency section.

of factors in Long Term Regional Transmission Planning will result in overvaluing transmission benefits, we believe that the clarifications discussed herein will alleviate the concerns underlying their rehearing arguments. As an initial matter, we find arguments that the categories of factors overlap to be moot because, as clarified above, transmission providers should avoid double counting the effects of overlapping factors when developing Long-Term Scenarios. While these rehearing parties are correct that Order No. 1920 requires transmission providers to incorporate seven categories of factors, transmission providers retain specific discretion with respect to how they account for each individual factor within a category to develop the required Long-Term Scenarios.[790] Further, as discussed below,[791] we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios, which will ensure that states have input into these factors and that these factors are not over or undervalued. We further note the Commission's finding in Order No. 1920 that transmission providers have discretion to reflect regional differences in the development of Long-Term Scenarios.[792]

277. We disagree with Designated Retail Regulators and with Undersigned States that Order No. 1920 provides insufficient evidence and analysis to conclude that use of the factors will result in cost-effective solutions. As discussed above and below, we, in this order, adopt a number of clarifications to ensure that states are consulted regarding the use of factors to develop Long-Term Scenarios, which, in turn, affect which Long-Term Regional Transmission Facilities are selected. We also emphasize that the states have a significant role in working to create a cost allocation method that ensures any solutions that are selected have costs allocated appropriately to beneficiaries. Because of this involvement, we find that the potential risk of the categories of factors leading to solutions that are not cost-effective is diminished, particularly in light of the requirement that selection criteria used in Long-Term Regional Transmission Planning must seek to maximize benefits accounting for costs over time without over-building transmission facilities.[793] Finally, we add that Order No. 1920 included substantial evidence in the record to demonstrate that existing transmission planning and cost allocation processes were insufficient to ensure just and reasonable rates by inadequately accounting on a forward-looking basis for known determinants of Long-Term Transmission Needs.[794]

b. Specific Categories of Factors and the Treatment of Factors in the Development of Long-Term Scenarios

i. Order No. 1920 Requirements

278. As stated above, in Order No. 1920, the Commission found that incorporating the seven categories of factors in the development of Long-Term Scenarios was necessary. The Commission stated that transmission providers may not exclude any of the categories of factors from being incorporated into the development of Long-Term Scenarios because each category includes important determinants of Long-Term Transmission Needs, and failing to incorporate all of the proposed categories of factors into Long-Term Scenarios would increase the likelihood that transmission providers would continue to underestimate or omit known determinants of Long-Term Transmission Needs.[795] The Commission considered category-specific record evidence in support of its determination to adopt each of the seven categories of factors.[796] The Commission declined to adopt additional categories of factors proposed by commenters because of a lack of substantial record evidence, or a finding that the commenter-proposed category of factors is already accounted for in other parts of Long-Term Regional Transmission Planning.[797]

279. The Commission in Order No. 1920 also required 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.[798] The Commission therefore required each Long-Term Scenario to account for and be consistent with, and not discount, factors in the first three categories of factors (*i.e.,* (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) once transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs. The Commission found that it is necessary to prohibit the 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.[799] Where two legally binding factors have conflicting or opposite implications for Long-Term Transmission Needs, however, transmission providers must reconcile this information while giving full effect to the maximum extent possible to all legally binding factors.[800]

280. The Commission allowed transmission providers to rely on the open and transparent stakeholder process discussed below to identify the factors in the first three required categories of factors. Transmission providers may independently identify factors in the first three categories of factors, but Order No. 1920 does not obligate transmission providers to do so.[801] Transmission providers retain the discretion to determine whether and how particular factors, including those in the first three categories of factors, are likely to affect Long-Term Transmission Needs.[802] Further, the Commission stated in Order No. 1920 that it expects that transmission providers will rely, at least in part, on information that relevant federal, state, and local

[790] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at P 412 (allowing transmission providers to propose to use additional categories of factors); *id.* P 413 (clarifying that incorporating categories of factors does not require exacting precision and allowing transmission providers to generalize how factors within the categories will, in the aggregate, affect the development of Long-Term Scenarios); *id.* P 415 (allowing transmission providers to determine whether specific factors will affect Long-Term Transmission Needs and allowing transmission providers not to account for specific factors that they determine do not affect such needs); *id.* P 417 (allowing transmission providers to determine how to account for specific factors within different Long-Term Scenarios).

[791] *Infra* Stakeholder Process and Transparency section.

[792] Order No. 1920, 187 FERC ¶ 61,068 at P 417.

[793] *Id.* P 964.

[794] *Id.* PP 112–133.

[795] *Id.* P 411.

[796] Order No. 1920, 187 FERC ¶ 61,068 at PP 448–449, 457–458, 464–466, 472–473, 481–484.

[797] *Id.* PP 492–494.

[798] *Id.* P 507.

[799] *Id.*

[800] *Id.* P 515.

[801] *Id.* P 508.

[802] *Id.* PP 510, 512.

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.[803]

281. The Commission provided transmission providers with additional discretion in how they account for each factor in Factor Categories Four through Seven (*i.e.,* (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) compared to how they account for each factor in the first three categories. For purposes of developing plausible and diverse Long-Term Scenarios, Order No. 1920 requires transmission providers, after they have determined that a specific factor in Factor Categories Four through Seven is likely to affect Long-Term Transmission Needs over the transmission planning horizon, to assess the extent to which the anticipated effects on Long-Term Transmission Needs due to that factor are likely to be realized in part, in full, or exceeded.[804] Transmission providers may choose to discount or to put more weight on the effects of factors in Factor Categories Four through Seven on Long-Term Transmission Needs, but only to the extent that each Long-Term Scenario remains plausible.[805]

282. The Commission disagreed with concerns that the additional flexibility afforded to transmission providers in how they account for each factor in Factor Categories Four through Seven could allow transmission providers to ignore these categories of factors. The Commission explained that Order No. 1920 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 all Long-Term Scenarios to be plausible.[806]

283. Further, the Commission explained that, because Order No. 1920 requires that all Long-Term Scenarios be consistent with and fully account for factors in Factor Category Three, which includes state-approved integrated resource plans and expected supply obligations of load-serving entities, the final rule does not ignore the Commission's fundamental responsibility under FPA section 217 to facilitate planning to meet the needs of load-serving entities.[807]

ii. Requests To Omit One or More Specific Categories of Factors

(a) Requests for Rehearing and Clarification

284. Designated Retail Regulators and Undersigned States request that the Commission grant rehearing on the grounds that Order No. 1920 requires transmission providers to consider several factors in Long-Term Regional Transmission Planning, and including these factors will result in rates that are unjust and unreasonable.[808] Arizona Commission avers that through Order No. 1920, the Commission is promoting certain preferred ''green'' energy generation resources by requiring transmission providers to incorporate seven categories of factors.[809] Arizona Commission states that these factors have political and policy considerations that do not belong in Arizona where the legislature has not mandated such costs, planning, or experimentation to the detriment of ratepayers.[810]

285. Designated Retail Regulators and Undersigned States both argue that Order No. 1920 usurps the role of the states in transmission planning by requiring that the plans and goals of some states, tribes, local governments, and private companies override the plans and goals of other entities while also forcing these entities to bear the cost burden.[811] Designated Retail Regulators and Undersigned States assert that Factor Categories One, Two, Four, Six, and Seven unjustly involve the policy goals of state and local governments and the commitments of utilities, and thus impose construction costs upon ratepaying loads without sufficient and measurable benefits.[812] Designated Retail Regulators and Undersigned States both state that there is insufficient evidence and analysis to support that use of these factors will result in cost-effective solutions.[813]

286. Ohio Commission Federal Advocate requests that the Commission grant rehearing on the grounds that the Commission acted arbitrarily and capriciously and abused its discretion because Order No. 1920 requires transmission providers to incorporate unreasonable categories of factors in the development of Long-Term Scenarios.[814] Specifically, Ohio Commission Federal Advocate is concerned that several factors would encourage a massive transmission build-out at unjust and unreasonable rates and requests that the Commission grant rehearing to remove Factor Categories One, Two, Six, and Seven as these factors are highly speculative and subject to change.[815] Ohio Commission Federal Advocate asserts that the Commission has not engaged in reasoned decision making by asserting that a best-available-data requirement will ensure these factors are incorporated in a meaningful way because even the best available data for a corporate commitment still amounts to nothing more than a corporate commitment.[816] Ohio Commission Federal Advocate claims that the Commission's attempt to mitigate the flaws of requiring transmission providers to incorporate factors in Factor Categories Four through Seven by allowing transmission providers to discount or give special weight to these factors is arbitrary and capricious. Further, Ohio Commission Federal Advocate asserts that Factor Categories Three, Four, and Five may be problematic if transmission projects are chosen to satisfy state or federal policies and, due to the other provisions of Order No. 1920, may not be properly cost allocated.[817]

287. Several petitioners request that the Commission grant rehearing on the grounds that the Order No. 1920 requirement to include Factor Category Seven (utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect long-term transmission needs) should be excluded from the development of Long-Term Scenarios.[818]

[803] *Id.* P 511.

[804] *Id.* P 516.

[805] *Id.* P 518.

[806] *Id.*

[807] *Id.* P 420.

[808] Designated Retail Regulators Rehearing Request at 7; Undersigned States Rehearing Request at 7.

[809] Arizona Commission Rehearing Request at 15.

[810] *Id.* at 22.

[811] Designated Retail Regulators Rehearing Request at 8; Undersigned States Rehearing Request at 7–8.

[812] Designated Retail Regulators Rehearing Request at 28; Undersigned States Rehearing Request at 27–28.

[813] Designated Retail Regulators Rehearing Request at 8 (citation omitted); Undersigned States Rehearing Request at 8 (citation omitted).

[814] Ohio Commission Federal Advocate Rehearing Request at 15.

[815] *Id.* at 16–17.

[816] *Id.* at 17.

[817] *Id.*

[818] Alabama Commission Rehearing Request at 4–5; Industrial Customers Rehearing Request at 49–54; Northern Virginia Rehearing Request at 4–7;

288. SERTP Sponsors argue that Factor Category Seven does not demonstrate reasoned decision making, is not supported by substantial evidence, and could intrude into matters involving retail customers subject to state regulation in an unduly discriminatory and preferential manner.[819] SERTP Sponsors assert that utility or corporate commitments and local policy goals are fundamentally retail concerns with arrangements subject to state-regulated tariffs and proceedings, and that the other categories of factors already encompass the transmission needs from these arrangements.[820] SERTP Sponsors also request clarification that Factor Category Seven is not intended to give preferential treatment to certain retail customers, like corporations, over others.[821]

289. Industrial Customers state that the Commission did not satisfactorily explain in Order No. 1920 why it found unpersuasive comments on the NOPR questioning the inclusion of utility or corporate commitments in Factor Category Seven, given that such commitments may not be firm or could change over the transmission planning horizon.[822] Further, Industrial Customers assert that the Commission's attempt to alleviate concerns by emphasizing in Order No. 1920 that transmission providers ''have discretion'' to account for ambiguity concerning these commitments actually raises several additional issues.[823] Industrial Customers argue that there are no clear rules to guide such discretion and that there is an alleged contradiction with Order No. 1920's ''earlier mandate to use publicly available information on *goals* and aspirations around corporate energy purchasing strategies.''[824] Industrial Customers add that one transmission provider, PJM, has publicly stated that it does not want such discretion due to the significant administrative burdens.[825]

290. Industrial Customers additionally state that Order No. 1920's inclusion of Factor Category Seven unduly discriminates against load that may be served by generation that may not be considered ''clean energy.''[826] Industrial Customers highlight the Commission's statement that Order No. 1920 responds to ''corporate, governmental, and utility commitments to rely on *certain* generation resources'' and argue that the word ''certain'' implies without definition or justification a limited subset within possible generation resources.[827]

291. Industrial Customers contend that many companies consider corporate sustainability and clean energy strategies to be proprietary and sensitive, so utilizing known and available corporate commitments and information without also having the underpinning analytical evidence cannot be reasonably relied on to inform future transmission planning scenarios.[828] Similarly, Industrial Customers state that Order No. 1920 does not demonstrate that corporate strategies and goals are known determinants or representative and reliable anecdotes able to be utilized in Long-Term Scenarios.[829]

292. Northern Virginia argues that the inclusion of ''corporate commitments'' as an independent factor in Category Factor Seven is arbitrary and capricious as this inclusion circumvents the planning process utilized by load serving utilities and state regulators to also meet these commitments.[830] Additionally, Northern Virginia states that corporate commitments are too ephemeral and uncertain to be included in Long-Term Scenarios, and asserts that transmission planning processes should utilize best data from utilities and state regulators that are required to plan to serve load.[831] Northern Virginia also argues that the Commission should not give special status to private corporations not charged with planning for the greater good, and that corporate commitments are not comparable to utility planning or governmental policy goals.[832] Northern Virginia states that any entities with corporate commitments can participate in existing stakeholder and customer processes.[833]

293. Virginia and North Carolina Commissions argue that the Commission should remove Factory Category Seven from the development of Long-Term Scenarios as transmission providers may not have the resources and should not be in a position to assess the reasonableness or accuracy of corporate or utility commitments.[834] Similarly, Virginia and North Carolina Commissions contend that it would be unreasonable to expect state entities to use their limited resources to evaluate and opine on such commitments or policy goals and that many states may be constrained from doing so if these commitments impact filings before the state entity.[835] Additionally, Virginia and North Carolina Commissions request that the Commission only permit the incorporation of public policy goals previously approved through a state regulatory process or, alternatively, clarify that transmission providers can fully discount any public policy factors that fall under Factor Category Seven.[836]

294. NRECA states that the Commission expanded the concept of Long-Term Transmission Needs well beyond reliability, economic, and public policy issues by adopting seven categories of factors, including Factor Category Seven.[837] NRECA asserts that the costs of facilities built to satisfy corporate commitments should be borne by the relevant corporations, not by those who do not benefit from the facility.[838]

295. Harvard ELI and PIOs request clarification to reframe Factor Category Seven.[839] Harvard ELI requests that the Commission clarify whether Factor Category Seven implements the existing requirement to plan for all transmission users on a comparable basis and further clarify that all long-term planning rules are similarly rooted in the open access comparability standard.[840] PIOs request clarification on whether required scenario factors additionally include city and consumer-side market preferences.[841]

(b) Commission Determination

296. We are unpersuaded by parties that request that the Commission set aside the requirement for transmission providers to incorporate the seven specified categories of factors into the development of Long-Term Scenarios, including requests to set aside the requirement to incorporate certain specific categories of factors.

NRECA Rehearing Request at 55; SERTP Sponsors Rehearing Request at 15–17; Virginia and North Carolina Commissions Rehearing Request at 6–8.

[819] SERTP Sponsors Rehearing Request at 16 (citations omitted).

[820] *Id.* at 15.

[821] *Id.* at 16.

[822] Industrial Customers Rehearing Request at 51 (citation omitted).

[823] *Id.* at 51–52 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 484).

[824] *Id.* at 52 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 413).

[825] *Id.* at 52–53 (citing PJM NOPR Initial Comments at 68).

[826] *Id.* at 54–55 (citations omitted).

[827] *Id.* at 55 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 261).

[828] *Id.* at 49–50.

[829] *Id.* at 50.

[830] Northern Virginia Rehearing Request at 4.

[831] *Id.* at 3–4.

[832] *Id.* at 4.

[833] *Id.* at 7–9.

[834] Virginia and North Carolina Commissions Rehearing Request at 7.

[835] *Id.*

[836] *Id.* at 8 (citation omitted).

[837] NRECA Rehearing Request at 54–55.

[838] *Id.* at 55.

[839] Harvard ELI Rehearing Request at 9–11; PIOs Rehearing Request at 61.

[840] Harvard ELI Rehearing Request at 9–11.

[841] PIOs Rehearing Request at 61.

Nevertheless, we believe certain clarifications adopted herein will alleviate the concerns these parties raise on rehearing. Specifically, our clarification that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios will help ensure that each Long-Term Scenario reflects states' preferences and future needs. However, with respect to Factor Category Seven, we set aside the requirement to include corporate commitments, as discussed further below.

297. We continue to 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. We reiterate that requiring transmission providers to incorporate the seven categories of factors into the development of Long-Term Scenarios is necessary because without doing so, transmission providers will fail to adequately consider drivers of Long-Term Transmission Needs.[842]

298. With regard to Arizona Commission's claim that Order No. 1920 favors ''green'' energy,[843] we reiterate that nothing in Order No. 1920 favors, promotes, or subsidizes particular types of generation resources over others and that the Commission's policies are technology and fuel neutral. Order No. 1920 does not endorse the merits of any laws and regulations or of any specific state-approved integrated resource plans.[844] Rather, we reiterate that states play a vital role in identifying the factors, especially in Factor Categories One, Two, and Seven, that transmission providers account for in Long-Term Regional Transmission Planning. We are unpersuaded by Arizona Commission and NRECA that the categories of factors requirements in Order No. 1920 include policy factors that have not been previously considered in regional transmission planning.[845] In Order No. 1000, the Commission required transmission providers to establish procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[846]

299. We are not persuaded by arguments that Factor Category One and Factor Category Two, which include state and local laws and regulations, will unjustly impose the policy goals of certain state and local governments on others.[847] We reiterate that 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.[848] In this case, we expect transmission providers to work with states to ensure the way those state laws and regulations are incorporated into Long-Term Scenarios reflects states' preferred implementation of those laws and regulations. We also reiterate that transmission providers must appropriately value the effect of states' policy decisions in regional transmission planning in order to ensure just and reasonable rates.[849]

300. Parties argue that the Commission's categories of factors requirements will impose formidable costs upon ratepaying loads that neither caused the need for the construction of additional transmission facilities nor measurably benefit from that construction and therefore are unjust and unreasonable and unduly discriminatory and preferential.[850] We disagree. The requirements of Order No. 1920, as clarified herein, ensure that Relevant States Entities, which represent consumers, have a voice in how factors within the categories of factors are accounted for, the development of Long-Term Scenarios that results from those factors, and the allocation of costs after a Long-Term Regional Transmission Facility is selected.[851] Nothing in Order No. 1920 changed the Commission's policy that costs must be allocated in a manner that is at least roughly commensurate with benefits, which ensures that ratepayers are not paying unjust and unreasonable rates.[852]

301. We also disagree with arguments from Designated Retail Regulators and Undersigned States that there is insufficient evidence and analysis to support the conclusion that use of Factor Categories One, Two, Four, Six, and Seven will result in cost-effective solutions.[853] We believe the collaboration between transmission providers and Relevant State Entities, where relevant, will ensure that those categories of factors are incorporated into the development of Long-Term Scenarios that identify Long-Term Regional Transmission Facilities that both meet the needs of states and provide reliability and economic value. At the same time, we believe that transmission providers cannot identify more efficient or cost-effective solutions to Long-Term Transmission Needs if they undervalue or entirely omit the consideration of some or all of the seven categories of factors.[854] The Commission based its determination for each category of factors on record evidence specific to each category of factors indicating that each required category of factors is essential to identifying Long-Term Transmission Needs.[855] To the extent states may be concerned about the resulting cost allocation, we note certain clarifications below that provide greater opportunities for input to Relevant State Entities with respect to cost allocation.[856]

302. For this reason, we also disagree with Ohio Commission Federal Advocate that the categories of factors requirements are unreasonable, arbitrary, and capricious, and will encourage a massive transmission build-out at unjust and unreasonable rates. We continue to find that the categories of factors that Order No. 1920 requires transmission providers to incorporate into the development of Long-Term Scenarios reflect the wide variety of drivers of Long-Term Transmission Needs and therefore are necessary to ensure the identification of more efficient or cost-effective transmission solutions to such needs. We also note

[842] Order No. 1920, 187 FERC ¶ 61,068 at P 410.

[843] Arizona Commission Rehearing Request at 15.

[844] Order No. 1920, 187 FERC ¶ 61,068 at PP 232, 437.

[845] Arizona Commission Rehearing Request at 22; NRECA Rehearing Request at 54–55.

[846] Order No. 1000, 136 FERC ¶ 61,051 at P 203; *see also S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 89–92 (upholding this Order No. 1000 requirement).

[847] *E.g.,* Designated Retail Regulators Rehearing Request at 28; Ohio Commission Federal Advocate Rehearing Request at 16–17; Undersigned States Rehearing Request at 27–28.

[848] Order No. 1920, 187 FERC ¶ 61,068 at P 435.

[849] *Id.* P 436.

[850] *E.g.,* Designated Retail Regulators Rehearing Request at 28; Ohio Commission Federal Advocate Rehearing Request at 16–17; Undersigned States Rehearing Request at 27–28.

[851] *See infra* Stakeholder Process and Transparency section; Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section.

[852] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at PP 419, 1419, 1471, 1513.

[853] *E.g.,* Designated Retail Regulators Rehearing Request at 8; Undersigned States Rehearing Request at 8.

[854] *E.g.,* Order No. 1920, 187 FERC ¶ 61,068 at PP 120, 228.

[855] *Id.* P 410; *see also id.* PP 391–395, 423–424, 438, 443–445, 450–452, 459, 467, 474–477 (summarizing record evidence that indicates that the seven categories of factors are essential to identifying Long-Term Transmission Needs).

[856] *See infra* Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section.

that, in Order No. 1920, the Commission responded to concerns that certain categories of factors are too speculative or subject to change and should not be incorporated into the development of Long-Term Scenarios.[857] Further, the Commission justified the framework for treating different types of categories of factors differently in the development of Long-Term Scenarios.[858]

303. However, we set aside, in part, the requirement for transmission providers to incorporate seven specific categories of factors in the development of Long-Term Scenarios. Specifically, we set aside the requirement for transmission providers to incorporate corporate commitments [859] in Factor Category Seven when developing Long-Term Scenarios. We find that requiring transmission providers to consider corporate commitments when developing Long-Term Scenarios may introduce the risk of one class of transmission users cross-subsidizing another class of transmission users. We clarify that we continue to require transmission providers to consider corporate commitments that are likely to affect Long-Term Transmission Needs as part of Long-Term Regional Transmission Planning to the extent that these commitments affect transmission customers' transmission needs, because transmission providers must plan for the needs of all transmission customers on a comparable basis under Order Nos. 888, 890, and 1000.[860] As such, we find that it is unnecessary to require transmission providers to separately identify corporate commitments as a factor in their development of Long-Term Scenarios given that the effects of such commitments will be sufficiently incorporated into Long-Term Regional Transmission Planning through the incorporation of other Factor Categories, such as Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities).

304. We agree with Harvard ELI's argument that transmission providers must consider how the contracts and purchasing plans of all transmission customers may affect Long-Term Transmission Needs in a comparable way to how transmission providers must consider utility purchasing plans and decisions. However, we disagree with Harvard ELI that the Commission's existing open access comparability standard requires transmission providers to plan for all transmission *users* on a comparable basis. Instead, as noted above, the open access comparability standard requires planning for transmission *customers* on a comparable basis. We emphasize this distinction because, in the context of Order No. 1920, transmission ''users'' could refer to retail customers of load-serving entities, and those load-serving entities are either transmission providers or transmission customers of transmission providers. In focusing on transmission users, Harvard ELI's request would inappropriately expand scope of the open access comparability standard to include retail customers. Therefore, we deny Harvard ELI's requested clarification.

305. Finally, we deny Northern Virginia's request to assign transmission facility costs related to corporate commitments through the Large Generator Interconnection Procedures. The Commission did not propose such a requirement in the NOPR and, as such, this request is beyond the scope of this proceeding.

306. Aside from corporate commitments, we otherwise sustain the requirement for transmission providers in each transmission planning region to incorporate Factor Category Seven into the development of Long-Term Scenarios, while recognizing the role of states in the incorporation of this category. Specifically, transmission providers must incorporate utility commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs into the development of Long-Term Scenarios. While we require transmission providers to incorporate this category of factors into the development of Long-Term Scenarios, we emphasize that, where relevant, each of the factors within the category should be the subject of discussion with the states who have the policy goals, and their preferences as far as how to integrate these goals should be taken into account when developing Long-Term Scenarios. We also find that utility commitments and federal, federally-recognized Tribal, state, and local policy goals could be drivers of Long-Term Transmission Needs.

307. We disagree with SERTP Sponsors and Industrial Customers that this requirement does not constitute reasoned decision making or engage with counterarguments in Order No. 1920 and note, as described above, that the requirement to incorporate Factor Category Seven into the development of Long-Term Scenarios was based on record evidence.[861] Further, the Commission acknowledged commenter concerns that utility, federally-recognized Tribal, and governmental goals may be more likely to change over the transmission planning horizon than factors in other required Factor Categories.[862] However, the Commission did not find that these commitments and goals are so speculative, amorphous, or unreliable that they should not be incorporated into Long-Term Scenarios at all.[863]

308. We also disagree with arguments that the inclusion of Factor Category Seven is unduly discriminatory or preferential.[864] The Commission requires that transmission providers plan for all transmission customers' transmission needs on a comparable basis.[865] We clarify that Factor Category Seven, as modified above, is not intended to single out certain utility commitments or federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs; instead, Factor Category Seven, as modified above, captures factors that are not fully represented in the other six categories of factors and also affect Long-Term Transmission Needs. As noted in Order No. 1920, transmission providers have discretion to determine whether a proposed factor in Factor Category Seven likely affects Long-Term Transmission Needs [866] and how such factors in Factor Category Seven should be considered,[867] but we clarify such discretion must be applied in a manner that ensures comparability among transmission customers. We also clarify that ''certain generation resources'' in Order No. 1920's reference to ''corporate, governmental, and utility commitments to rely on certain generation resources,'' which, as modified on rehearing, is now

[857] Order No. 1920, 187 FERC ¶ 61,068 at PP 229, 231, 473.

[858] *Id.* PP 484, 507.

[859] We clarify that we distinguish in this context between ''corporate commitments'' and utility commitments that are made by transmission providers and load-serving entities, regardless of their corporate form.

[860] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 435 (''The Commission has broad authority to remedy undue discrimination by ensuring that transmission providers plan for the needs of their customers on a comparable basis. That fundamental requirement was adopted in Order No. 888 and the reforms adopted herein should ensure that it will be implemented properly.'' (footnote omitted)).

[861] Order No. 1920, 187 FERC ¶ 61,068 at PP 474–477 (summarizing record evidence indicating that Factor Category Seven is essential to identifying Long-Term Transmission Needs).

[862] *Id.* P 484.

[863] *Id.*

[864] SERTP Sponsors Rehearing Request at 16; Industrial Customers Rehearing Request at 54.

[865] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 435.

[866] Order No. 1920, 187 FERC ¶ 61,068 at PP 415, 417.

[867] *Id.* P 516

''governmental and utility commitments,'' does not refer to a certain resource type, or limit consideration of such government or utility commitments to only those commitments to rely on renewable resources.[868] Rather, this requirement means that transmission providers must consider the generation resources that a federal, state, or local government entity, federally-recognized Tribe, or utility has chosen to rely on regardless of the resource type.

309. In response to Virginia and North Carolina Commissions' request as to whether transmission providers may discount public policy factors within Factor Category Seven to zero, we reiterate that, with respect to Factor Category Seven, transmission providers have discretion as to how they account for these factors. We also clarify that transmission providers may conclude that certain factors within Factor Category Seven do not affect Long-Term Transmission Needs and, therefore, do not need to account for them when incorporating Factor Category Seven into the development of Long-Term Scenarios.[869]

310. Regarding Industrial Customers' concern that the quality of information on utility commitments make Factor Category Seven unworkable, we note the clarification below that transmission providers may rely on the open and transparent stakeholder process to identify the factors in Factor Category Seven, as modified above, in the same manner that they may rely on the open and transparent stakeholder process to identify the factors in Factor Categories One through Three.[870] We continue to believe that federal, state, and local government entities, federally-recognized Tribes, utilities, load-serving entities, and their retail regulators that participate in the stakeholder process are distinctly well-positioned to provide transmission providers with vital information regarding factors in Factor Category Seven, as modified above.[871] In response to Industrial Customers' claim that the best information may be confidential,[872] we clarify that transmission providers may include what they believe to be appropriate confidentiality protections in their compliance proposals to account for proprietary commitments. The Commission will evaluate those proposals by using the established principles in Order No. 890,[873] 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 transmission planning principles.

311. We disagree with Industrial Customers' argument that the Commission's emphasis on transmission provider discretion is problematic.[874] Order No. 1920, with Factor Category Seven as modified above, strikes the right balance by allowing transmission providers discretion as to the treatment of factors within Factor Category Seven when developing Long-Term Scenarios. In contrast to Industrial Customers' claim,[875] we do not believe that transmission providers need clear rules or standards for implementing their discretion over incorporating Factor Category Seven, as modified above, in the development of Long-Term Scenarios. We find that transmission providers can rely on their expert judgement and the information provided to them through the open and transparent stakeholder process to develop three plausible Long-Term Scenarios for purposes of identifying Long-Term Transmission Needs. Furthermore, we continue to find that concerns regarding the administrative burden of identifying specific factors are addressed by allowing transmission providers to rely on the open and transparent stakeholder process to identify factors.[876] We find that our clarification that transmission providers may rely on the open and transparent stakeholder process to identify the factors in Factor Category Seven,[877] as well as our decision to exclude corporate commitments from that Factor Category, renders moot Industrial Customers' claim that Order No. 1920 forces transmission providers to account for corporate energy commitments and goals of ''all potentially known or capable-of-being known energy commitments or contracts.'' [878]

312. We recognize that utility commitments and federal, federally-recognized Tribal, state, and local policy goals in Factor Category Seven may initially surface as retail concerns that are addressed through arrangements with retail providers; [879] however, this fact does not obviate the need for transmission providers to account for them in the development of Long-Term Scenarios. We acknowledge that there could be an overlap between Factor Category Seven, as modified above, and other categories (*e.g.,* integrated resource plans in Factor Category Three), because utility commitments and policy goals may be addressed through arrangements with retail providers. As discussed above,[880] transmission providers should avoid double counting the anticipated effects that those factors have on assumptions used to develop Long-Term Scenarios where the impact of factors overlaps, such that transmission providers must incorporate those factors once in the appropriate Factor Categories One through Three, not Factor Categories Four through Seven.

313. We disagree with NRECA's claim that the inclusion of Factor Category Seven expands the definition of Long-Term Transmission Needs beyond reliability, economic, or public policy issues. The Commission was clear that 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.[881] Foundationally, and consistent with our clarification that economic drivers contribute to Long-Term Transmission Needs,[882] we find that all seven categories of factors in Order No. 1920 pertain to Long-Term Transmission Needs because they affect the reliable and economic operation of the interconnected transmission system. The categories of factors requirements are intended to address certain

[868] *Id.* P 261; Industrial Customers Rehearing Request at 55.

[869] Order No. 1920, 187 FERC ¶ 61,068 at P 415.

[870] *Supra infra* Stakeholder Process and Transparency section (clarifying that transmission providers have no independent obligation to identify factors in Factor Category Seven and may rely on stakeholders to identify factors in Factor Category Seven).

[871] Order No. 1920, 187 FERC ¶ 61,068 at P 530.

[872] Industrial Customers Rehearing Request at 49–50.

[873] Order No. 890, 118 FERC ¶ 61,119 at PP 471–476; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 466 (clarifying 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).

[874] Industrial Customers Rehearing Request at 51–53.

[875] *Id.* at 52.

[876] Order No. 1920, 187 FERC ¶ 61,068 at P 508.

[877] *See infra* Stakeholder Process and Transparency section.

[878] Industrial Customers Rehearing Request at 53.

[879] SERTP Sponsors Rehearing Request at 15. In light of the discussion above, we continue to conclude that Order No. 1920—including Factor Category Seven, as modified—is within the Commission's authority notwithstanding that considerations relevant to Factor Category Seven may also arise in the context of retail transactions. *See supra* Order No. 1920 Is Consistent with the FPA and Precedent Regarding the Commission's Authority section (explaining that where the Commission regulates within its statutory authority, that regulation does not run afoul of the jurisdictional lines drawn in the FPA irrespective of any effects on areas of reserved state authority).

[880] *Supra* Requirement to Incorporate Categories of Factors section.

[881] Order No. 1920, 187 FERC ¶ 61,068 at P 299.

[882] *See supra* Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs section.

deficiencies in the Commission's existing regional transmission planning requirements, including the failure to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.[883]

iii. Other Specific Required Categories of Factors

(a) Requests for Rehearing and Clarification

314. NRECA requests rehearing of the Commission's holding in Order No. 1920 that transmission providers have the discretion to determine that factors in Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities) may not affect Long-Term Transmission Needs.[884] NRECA argues that Order No. 1920 is in error because the Commission took action in this regard that is at odds with the needs of load-serving entities in violation of FPA section 217(b)(4).[885] NRECA acknowledges that the Commission explained in Order No. 1920 that the final rule is consistent with FPA section 217(b)(4) and the interpretation of that statute adopted when the D.C. Circuit upheld Order No. 1000 in *South Carolina Public Service Authority* v. *FERC.*[886] Nonetheless, NRECA claims that Order No. 1920 is different from Order No. 1000, and therefore that decision is not dispositive—particularly as to Order No. 1920's treatment of state-approved integrated resource plans and the expected supply obligations as discretionary.[887] NRECA further argues that the Commission should revisit its conclusion that *South Carolina Public Service Authority* v. *FERC* remains binding precedent, because the D.C. Circuit upheld Order No. 1000's compliance with section 217(b)(4) using the deferential standard of review in *Chevron U.S.A. Inc.* v. *Natural Resources Defense Council, Inc.,*[888] which was under review by the U.S. Supreme Court at the time NRECA submitted its request for rehearing.[889] NRECA further argues that the Commission's decision in this regard was arbitrary and capricious because Order No. 1920 was not ''based on a consideration of the relevant factors'' and ''entirely failed to consider an important aspect of the problem.''[890]

315. SERTP Sponsors request the following clarifications regarding specific categories of factors. With regard to Factor Categories One through Three, SERTP Sponsors request that the Commission expressly clarify that the open and transparent stakeholder process established by transmission providers is not intended to create an opportunity to relitigate or dispute the underlying integrated resource plans, resource projections, or laws and regulations, but instead, simply intends to create a forum in which such inputs can be brought forth to examine the potential impact on Long-Term Transmission Needs.[891] Regarding Factor Category Three, SERTP Sponsors request that the resource planning and procurement processes of non-jurisdictional transmission providers, such as those of the non-jurisdictional SERTP Sponsors, that have been approved by their respective governing authorities should be included in this Factor Category Three as scenario inputs that are to be included without discount.[892] SERTP Sponsors also request clarification that ''federal, federally-recognized Tribal, state, and local laws and regulations'' is intended to encompass only ''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 at the federal level'' as established in Order No. 1000, albeit with the addition of Tribal laws and regulations.[893] Similarly, SERTP Sponsors request clarification that for Factor Category One, such legally binding obligations, incentives (*e.g.,* tax credits), and/or restrictions must be enacted by legislatures or promulgated by the relevant agency or Tribal authority.[894]

316. PIOs request rehearing of the Commission's findings regarding Factor Categories Four and Seven because they assert that the Commission erred when it failed to create specific guardrails to prevent transmission providers from minimizing these two categories of factors.[895] PIOs argue that the Commission must provide specific guardrails for Factor Categories Four and Seven to ensure that transmission needs are accurately assessed.[896] PIOs argue that Order No. 1920 allows ''boundless discounting'' of these categories, which ''creates an opportunity for transmission providers to functionally ignore the Commission's mandate.''[897]

317. PIOs contend that the evidence in the record does not substantiate the Commission's dismissal of the concern that the additional discretion granted to transmission providers regarding the last four categories of factors could functionally minimize these categories.[898] Regarding Factor Category Four, PIOs urge the Commission to maintain a list of best available data.[899] Regarding Factor Category Seven, PIOs request that the Commission limit the discounting of utility and corporate commitments by creating a presumption that transmission providers' discounting cannot assume greater failure to reach utility and corporate commitments than has occurred in the previous 10 years.[900]

(b) Commission Determination

318. We disagree with NRECA's rehearing arguments and continue to find that, while transmission providers must incorporate into the development of Long-Term Scenarios all factors in Factor Category Three (state-approved integrated resource plans and expected supply obligations for load-serving entities) that the transmission providers determine are likely to affect Long-Term Transmission Needs, transmission providers have the discretion as to whether they must account for a specific factor in Factor Category Three in the development of Long-Term Scenarios by concluding it is likely to affect Long-Term Transmission Needs.[901] We continue to believe that the framework adopted in Order No. 1920 regarding categories of factors strikes the right balance between prescriptive

[883] Order No. 1920, 187 FERC ¶ 61,068 at P 418.

[884] NRECA Rehearing Request at 37–39 (citing Order No. 1920, 187 FERC ¶ 61,068 PP 507, 510); *see also* East Kentucky Rehearing Request at 2–3 (arguing that Order No. 1920 violates FPA section 217(b)(4) by treating state-approved integrated resource plans and expected supply obligations for load-serving entities as discretionary factors in Factor Category Three (citation omitted)); *id.* at 1 (stating that East Kentucky ''specifically adopts the majority of issues identified by NRECA and incorporates the bases and arguments for rehearing set forth in the NRECA Rehearing Request for those issues'').

[885] NRECA Rehearing Request at 39–40 (citing 16 U.S.C. 824q(b)(4)).

[886] *Id.* at 40–41 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 283).

[887] *Id.* at 41.

[888] *Id.* (citing *Chevron U.S.A. Inc.* v. *Nat. Res. Def. Council, Inc.,* 467 U.S. 837 (1984); *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 54).

[889] *Id.* (citing *Loper Bright Enters.* v. *Raimondo,* No. 22–451; *Relentless, Inc.* v. *Dep't of Commerce,* No. 22–1219 (U.S. argued Jan. 17, 2024)).

[890] *Id.* at 41–42 (quoting *State Farm,* 463 U.S. at 43).

[891] SERTP Sponsors Rehearing Request at 5.

[892] *Id.* at 6.

[893] *Id.* at 14–15 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 2).

[894] *Id.*

[895] PIOs Rehearing Request at 33–35.

[896] *Id.* at 33.

[897] *Id.*

[898] *Id.*

[899] *Id.* at 34.

[900] *Id.* at 35.

[901] Order No. 1920, 187 FERC ¶ 61,068 at PP 447, 510.

requirements and flexibility.[902] Transmission providers determining whether a particular factor is likely to affect Long-Term Transmission Needs does not allow them to simply pick-and-choose one factor that they may prefer over another factor. Instead, allowing transmission providers to determine whether to account for a specific factor by concluding it is likely to affect Long-Term Transmission Needs is necessary to ensure that transmission providers develop accurate assumptions on which to base their Long-Term Scenarios.[903] Further, Order No. 1920 builds on the foundation of Order No. 890, and specifically the comparability principle, which requires that transmission providers treat similarly situated customers comparably in the transmission planning process.[904]

319. We believe that the vast majority of factors in Factor Category Three, which represent state-approved integrated resource plans and expected supply obligations for load-serving entities, will likely affect Long-Term Transmission Needs. Nevertheless, we cannot foresee every potential factor that may be identified, and we therefore find it appropriate to preserve transmission providers' discretion to conclude that a specific factor (even in Factor Category Three) will have limited or no impact on Long-Term Transmission Needs. We also emphasize, as discussed below,[905] that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to incorporate categories of factors into the development of Long-Term Scenarios in such a way that states will play an important role in ensuring that state-approved integrated resource plans are incorporated in the manner they are expected to be implemented.

320. We also disagree with NRECA's argument that the Commission acted at odds with the needs of load-serving entities in violation of FPA section 217(b)(4) by providing transmission providers with the discretion to not account for factors in Factor Category Three that a transmission provider finds are unlikely to affect Long-Term Transmission Needs. If a factor is unlikely to affect Long-Term Transmission Needs, excluding that factor in the transmission planning process is unlikely to negatively affect the needs of load-serving entities. Contrary to NRECA's claims, FPA section 217(b)(4) does not require the Commission to require transmission providers to account for factors in the development of Long-Term Scenarios that do not affect Long-Term Transmission Needs. We continue to find that Order No. 1920 satisfies the Commission's obligation under FPA section 217(b)(4) because Order No. 1920 facilitates the planning and expansion of transmission facilities to meet load-serving entities' needs.[906] Long-Term Regional Transmission Planning, as clarified herein, is intended to enhance the transmission planning process for states, load-serving entities, and other interested parties, and, to that end, requires transmission providers to account for factors (including load-serving entities' expected supply obligations) that are likely to affect Long-Term Transmission Needs in the development of Long-Term Scenarios.

321. Further, we disagree with NRECA that the U.S. Supreme Court's decision in *Loper Bright Enterprises* v. *Raimondo*[907]—in which the Court overruled *Chevron U.S.A. Inc.* v. *Natural Resources Defense Council, Inc.*—requires us to reconsider the D.C. Circuit's holding in *South Carolina Public Service Authority* v. *FERC* as to the meaning of FPA section 217(b)(4).[908] The D.C. Circuit interpreted section 217(b)(4) and determined that this provision requires the Commission to ''facilitate the planning of a reliable grid'' by ''seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations.''[909] Order No. 1920 did not reinterpret FPA section 217(b)(4), but rather applied the interpretation adopted by the D.C. Circuit. Moreover, we believe the interpretation set forth by the Commission in Order No. 1000, endorsed by the D.C. Circuit in *South Carolina Public Service Authority* v. *FERC* and applied in Order No. 1920, remains the most reasonable reading of this statutory provision.[910] Fundamentally, meeting the reasonable needs of load-serving entities to satisfy their service obligations requires that sufficient transmission capacity is available to deliver power when it is needed, and fostering a reliable transmission system is the best way to ensure that such capacity is available. Order No. 1920's requirements are designed to achieve precisely that development of sufficient transmission capacity to ensure reliable and affordable delivery of needed power to meet the reasonable needs of load-serving entities, and therefore we find that it complies with FPA section 217(b)(4).

322. We grant SERTP Sponsors' request for clarification regarding the first three categories of factors and clarify that nothing in Long-Term Regional Transmission Planning is intended to relitigate or dispute the outcomes of the underlying integrated resource plans, resource projections, or laws and regulations that are (or are not) incorporated into the development of Long-Term Scenarios. The open and transparent stakeholder process required in Order No. 1920 is a forum that provides stakeholders, including 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.[911] For purposes of identifying Long-Term Transmission Needs, every factor is an input that transmission providers consider when determining the assumptions to use in the development of Long-Term Scenarios. Through the stakeholder process, states, transmission providers and stakeholders will have the opportunity to discuss how a factor would affect assumptions used to develop Long-Term Scenarios, if it does at all, and how the effect varies in different Long-Term Scenarios.

323. In addition, we grant SERTP Sponsors' request for clarification regarding non-jurisdictional entities,[912] in part. We clarify that, where a non-

[902] *Id.* P 417.

[903] *Cf. id.* P 530 (discussing importance of transmission providers being able to develop more accurate assumptions to serve as the basis for their Long-Term Scenarios).

[904] *Id.* P 14 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 418–601); *see also* Order No. 890, 118 FERC ¶ 61,119 at PP 494–495 (discussing the comparability principle).

[905] *Infra* Stakeholder Process and Transparency section.

[906] Order No. 1920, 187 FERC ¶ 61,068 PP 283, 420.

[907] 144 S.Ct. 2244 (2024).

[908] NRECA Rehearing Request at 41 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 54).

[909] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 90. Moreover, even if the D.C. Circuit had relied on *Chevron* in reaching this conclusion, the Supreme Court confirmed that ''mere reliance'' on *Chevron* is ''not enough to justify overruling a statutory precedent.'' *Loper Bright,* 144 S.Ct. at 2273.

[910] *Compare* Order No. 1000, 136 FERC ¶ 61,051 at P 108 (''[T]his Final Rule is consistent with section 217 because it supports the development of needed transmission facilities, which ultimately benefits load-serving entities.''), *with S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 90 (''Section 217 (b)(4) requires the Commission to facilitate the planning of a reliable grid, which is exactly what the Commission has done in the challenged orders.''); Order No. 1920, 187 FERC ¶ 61,068 at P 283 (''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.''' (alteration in original) (citation omitted)).

[911] Order No. 1920, 187 FERC ¶ 61,068 at P 528.

[912] SERTP Sponsors Rehearing Request at 6.

jurisdictional entity is a transmission customer of one or more transmission providers in a transmission planning region, the transmission providers must plan for the non-jurisdictional entity's needs as a transmission customer as it would for the needs of any other transmission customer, including any resource planning and procurement processes that have been approved by the respective governing authorities under Factor Category Three, for purposes of complying with the requirements of Order No. 1920. For example, each Long-Term Scenario must account for and be consistent with these factors once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs.[913] However, we further clarify that transmission providers may *not* plan for the needs of a non-jurisdictional utility transmission provider if that non-jurisdictional transmission provider has not enrolled in the transmission planning region and thereby has not agreed to any cost allocation method applicable to selected Long-Term Regional Transmission Facilities.[914] If the transmission provider were to plan for and consider non-jurisdictional transmission providers' Long-Term Transmission Needs without a way to ensure the non-jurisdictional transmission provider contributes to the costs of the resulting Long-Term Regional Transmission Facilities, the resulting cost allocation could violate the cost causation principle and result in free-ridership.[915]

324. In response to SERTP Sponsors' request for clarification regarding the meaning of ''laws and regulations,'' we clarify that Order No. 1920 adopts the meaning of the terms used in the NOPR, namely ''enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction.'' [916] Order No. 1920 amended the term ''statutes'' used in the NOPR by adding the duly enacted and legally binding obligations of federally-recognized Tribes.[917] We reiterate that Factor Categories One and Two include laws and regulations at the federal, federally-recognized Tribal, state, and local level.[918]

325. We disagree with PIOs' request for rehearing to create more prescriptive requirements for 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) and Factor Category Seven (utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs).[919] We reiterate that the framework that the Commission adopted in Order No. 1920 regarding the incorporation of categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility.[920] We believe that the requirements for transmission providers to incorporate (*i.e.,* more than merely consider) categories of factors in the development of Long-Term Scenarios, as well as to develop plausible Long-Term Scenarios with the best available data,[921] are adequate to safeguard against ''boundless discounting'' and opportunities to ''functionally ignore the Commission's mandate.'' [922]

326. More specifically, we disagree with PIOs' request to require on rehearing that transmission providers incorporate certain factors from a Commission-maintained list of data sources for Factor Category Four. As an initial matter, we find that it is unnecessary to grant PIOs' request because transmission providers' technical expertise and the required open and transparent stakeholder process to identify factors are sufficient to ensure that transmission providers implement the requirements of Long-Term Regional Transmission Planning. In addition to the Commission's concerns regarding regional variation and stifled innovation identified in Order No. 1920,[923] we conclude that there are practical challenges associated with the Commission establishing and maintaining a list of data sources. For example, transmission providers already collect data similar to the data needed for these factors for other applications, and the Commission would be duplicating this data collection effort. We believe that transmission providers working with Relevant State Entities and other stakeholders in their regions are better equipped to understand the unique circumstances of their regions and to compile data and inputs for the required categories of factors.

327. With respect to Factor Category Seven, we decline to limit the discounting of utility and corporate commitments as proposed by PIOs.[924] In this case, we find that transmission providers may face practical challenges in accurately quantifying the historical rate of failure for utility commitments; moreover, the historical rate of failure is not necessarily determinative of future achievement rates for such commitments. In addition, limiting how transmission providers manage the uncertainty associated with utility commitments may have unintended consequences. For example, such a limit would not allow transmission providers to adapt their treatment of utility commitments in response to, for example, industry-wide changes that make it more challenging for utilities to meet prior commitments. We believe that the existing requirements in Order No. 1920 [925] are adequate to safeguard against boundless discounting of factors in Factor Category Seven.[926]

iv. Requests for Additional Requirements

(a) Requests for Rehearing

328. Invenergy requests rehearing, asserting that the Commission erred by not requiring transmission providers to include ''advanced-stage'' merchant high-voltage direct current (HVDC) transmission facilities in the list of factors to be considered when developing Long-Term Scenarios.[927] Invenergy claims this omission is unduly discriminatory against advanced-stage merchant HVDC transmission.[928] Invenergy also asserts that the Commission failed to consider significant evidence in Order No. 1920 because the Commission failed to

[913] Order No. 1920, 187 FERC ¶ 61,068 at PP 507, 510.

[914] *Cf.* Order No. 1000–A, 139 FERC ¶ 61,132 at P 276 (''[T]he regional transmission planning process is *not required* to plan for the transmission needs of such a non-[jurisdictional] utility transmission provider that has not made the choice to join a transmission planning region.'' (emphasis added)).

[915] *El Paso Elec. Co.* v. *FERC,* 76 F.4th at 363–66.

[916] NOPR, 179 FERC ¶ 61,028 at P 104 n.189; *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 2. We clarify here that the definition of ''laws and regulations'' includes laws and regulations duly enacted by local jurisdictions, even where there are differences in how these jurisdictions enact laws or promulgate regulations.

[917] Order No. 1920, 187 FERC ¶ 61,068 at P 434.

[918] *Id.* P 409. It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[919] PIOs Rehearing Request at 33.

[920] Order No. 1920, 187 FERC ¶ 61,068 at P 417.

[921] *Id.* PP 413–414.

[922] PIOs Rehearing Request at 33.

[923] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 639 (declining to impose further requirements as to data uniformity because regional variation may make uniformity challenging and because it could stifle innovation that may improve Long-Term Regional Transmission Planning).

[924] The issue of discounting corporate commitments is rendered moot by our decision to set aside the requirement to include these commitments in Factor Category Seven above.

[925] *Id.* PP 413–414.

[926] PIOs Rehearing Request at 33.

[927] Invenergy Rehearing Request at 2, 6–7.

[928] *Id.* at 10.

address AEE's comments, which argued that merchant HVDC transmission facilities must be included in at least one Long-Term Scenario in order to address potential undue discrimination against merchant HVDC transmission facilities. According to Invenergy, AEE asserted that it is important to include merchant HVDC transmission facilities in at least one Long-Term Scenario because merchant HVDC transmission facilities are developed by nonincumbent transmission developers and this inclusion guards against potential undue discrimination.[929] In addition, Invenergy claims that failure to utilize critical and readily available information will result in Long-Term Scenarios that do not accurately reflect the topography of the system, and that this information should be included to guard against potential undue discrimination from incumbent transmission owners.[930] Invenergy argues that the Commission ignored significant evidence in the record from Invenergy and others on this issue.[931]

(b) Commission Determination

329. In response to Invenergy's request for rehearing, we reiterate that the Commission did not propose specific requirements in the NOPR regarding merchant HVDC transmission facilities under development and was not persuaded by the evidence in the record that it should include advanced-stage HVDC transmission facilities in the minimum set of known determinants of Long-Term Transmission Needs.[932] Invenergy has not clearly articulated how merchant HVDC transmission facilities are essential to identifying, or are known and identifiable drivers of, Long-Term Transmission Needs.

330. In the NOPR, the Commission referenced merchant transmission facilities only once,[933] and that reference was in the context of a larger proposed requirement that the Commission declined to adopt in Order No. 1920.[934] Order No. 1920 addressed specific deficiencies with the Commission's existing regional transmission planning and cost allocation requirements but did not identify issues surrounding merchant transmission as one of those deficiencies.[935]

331. We disagree with Invenergy's claim that the exclusion of proposed but not yet built merchant HVDC transmission facilities from the required factors underlying the Long-Term Scenarios is unjust and unreasonable.[936] In Order No. 1920, the Commission described the seven specific categories of factors required by the Commission as "essential to identifying Long-Term Transmission Needs" and "known and identifiable drivers of Long-Term Transmission Needs." [937] Although Invenergy claimed that one of its merchant HVDC transmission facilities could *address* transmission needs,[938] Invenergy has failed to clearly articulate how proposed but not yet built merchant HVDC transmission facilities are essential to identifying, or are known and identifiable drivers of, Long-Term Transmission Needs. However, as indicated in Order No. 1920, transmission providers may be aware of additional categories of factors beyond those adopted in the final rule that drive Long-Term Transmission Needs and may incorporate additional categories of factors into the development of Long-Term Scenarios.[939] We clarify that, if transmission providers elect to use additional categories of factors beyond the required categories of factors in Order No. 1920 in the development of Long-Term Scenarios, the transparency requirements set forth in Order No. 1920 also apply to the additional categories of factors.[940] Pursuant to this clarification, transmission providers must publish on the public portion of an OASIS or other public website: (1) the list of each additional categories of factors, and the factors in each of the additional categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each additional category of factors and 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 additional category of factors and each of the additional factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in each additional category of factors; and (5) a list of the factors that they considered but did not incorporate in each additional category of factors in their Long-Term Scenarios. Consistent with Order No. 1920, we find that this transparency is necessary to make clear to stakeholders which specific additional categories of factors and factors transmission providers incorporate into Long-Term Scenarios and how they are incorporated. We believe this posting requirement for additional categories of factors will also provide greater transparency into how transmission providers develop Long-Term Scenarios, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors.[941] Accordingly, in transmission planning regions where proposed HVDC transmission facilities may play a role in shaping Long-Term Transmission Needs, transmission providers have the flexibility to consider and incorporate such facilities into their Long-Term Scenarios.

332. We also disagree with Invenergy's argument that the Commission has failed to direct transmission providers to use critical—and readily available—information related to the future electric power system, which renders the resulting Long-Term Scenarios unjust and unreasonable.[942] Order No. 1920 requires transmission providers to develop Long-Term Scenarios with 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.[943] In addition, in Order No. 1920, the Commission found that transmission providers must use best available data when determining whether each factor is likely to affect Long-Term

929 Invenergy Rehearing Request at 9 (citing AEE NOPR Reply Comments at 19).

930 *Id.* at 8–9.

931 *Id.* at 9.

932 *See* Order No. 1920, 187 FERC ¶ 61,068 at P 493.

933 NOPR, 179 FERC ¶ 61,028 at P 150 (In the context of the NOPR proposal for the identification of geographic zones, the Commission proposed to include "any merchant or other entity commitments to build . . . transmission facilities" as one of seven mandatory considerations to assess generation developers' commercial interest in developing generation within each designated geographic zone.).

934 Order No. 1920, 187 FERC ¶ 61,068 at P 665 (stating that "the [identification of geographic zones] NOPR proposal is not warranted at this time").

935 *Id.* P 139 ("[W]e 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.").

936 Invenergy Rehearing Request at 8.

937 Order No. 1920, 187 FERC ¶ 61,068 at P 410.

938 Invenergy Initial NOPR Comments at 7 ("A planned 5,000 MW HVDC line such as Grain Belt's would be a significant system addition, and could itself provide system benefits or even address transmission needs otherwise identified through the planning process. . . .").

939 Order No. 1920, 187 FERC ¶ 61,068 at P 493.

940 *See id.* PP 528–533.

941 *Id.* P 534.

942 Invenergy Rehearing Request at 9.

943 Order No. 1920, 187 FERC ¶ 61,068 at P 633.

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.[944]

333. We also disagree with Invenergy's claim that the Commission ignored significant evidence in the record.[945] We remain unpersuaded 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.[946] Invenergy's experience with its Grain Belt project in the MISO Long Range Transmission Plan speaks to a separate issue currently before the Commission.[947]

334. Finally, we disagree with Invenergy's argument that the Commission's inclusion of a wide range of factors, including generation interconnections, but exclusion of advanced-stage merchant HVDC facilities is unduly discriminatory and opens such developers to further potential undue discrimination.[948] The Commission found it appropriate to require transmission providers to incorporate Factor Category Six (generator interconnection requests and withdrawals) into the development of Long-Term Scenarios because generation interconnection queues provide important information about future generation development over the transmission planning horizon and therefore affect Long-Term Transmission Needs.[949] We cannot make a similar finding for advanced-stage merchant HVDC transmission based on the record in this proceeding, nor do we conclude (and Invenergy has not demonstrated) that the exclusion of advanced-stage merchant HVDC facilities from the required categories of factors opens merchant transmission developers to potential undue discrimination. We also are not persuaded by Invenergy's reference to AEE's comments claiming that being a nonincumbent transmission developer rises to the level of potential undue discrimination that must be remedied by requiring merchant HVDC to be included in Long-Term Scenarios. To the extent that similar potential undue discrimination claims for nonincumbent merchant HVDC transmission developers are pending in other proceedings, the Commission will address those claims based on the evidence in those proceedings. We note that AEE provides no evidence of potential undue discrimination and that AEE itself has not filed a rehearing request on this issue. Finally, we clarify that transmission providers, in addressing interconnection requests and withdrawals under Factor Category Six, must include merchant transmission developer interconnection requests in the development of Long-Term Scenarios, and in a manner comparable to other interconnection requests.

c. Stakeholder Process and Transparency

i. Order No. 1920 Requirements

335. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise the regional transmission planning process 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. The Commission further required transmission providers to publish on the public portion of an OASIS or other public website the following information: (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.[950] In addition, the Commission required transmission providers to 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.[951] The Commission explained that this requirement will provide greater transparency into how transmission providers develop Long-Term Scenarios, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors,[952] and the Commission explained that this transparency also ensures that transmission providers review stakeholder-proposed factors in a fair and non-discriminatory manner.[953]

336. The Commission also required transmission providers, consistent with Order No. 890's transparency transmission planning principle, to make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario.[954] Given the importance of a robust stakeholder process to developing more accurate assumptions to serve as the basis for Long-Term Scenarios, Order No. 1920 required transmission providers to give stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate into the development of Long-Term Scenarios, including how to account for a specific factor in terms of how the factor may affect Long-Term Transmission Needs. The Commission explained that this meaningful opportunity 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.[955]

337. The Commission further found in Order No. 1920 that 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 well-positioned to provide transmission providers with vital information on how the factors over which they have authority or that they govern are likely to influence Long-Term Transmission Needs over the transmission planning

[944] *Id.*

[945] Invenergy Rehearing Request at 9 (''As demonstrated above, multiple commenters, including Invenergy, the Clean Energy Associations, and others placed evidence into the record explaining why merchant HVDC transmission facilities must be included.'').

[946] Order No. 1920, 187 FERC ¶ 61,068 at P 493.

[947] *Invenergy Transmission LLC* v. *Midcontinent Indep. Sys. Operator, Inc.,* Complaint, Docket No. EL22–83–000 (filed Aug. 8, 2022).

[948] Invenergy Rehearing Request at 10.

[949] Order No. 1920, 187 FERC ¶ 61,068 at P 472.

[950] *Id.* P 528.

[951] *Id.* P 533.

[952] *Id.* P 534.

[953] *Id.* P 535.

[954] *Id.* P 305 (citing Order No. 890, 118 FERC ¶ 61,119 at P 471).

[955] *Id.* PP 529–530.

horizon.[956] The Commission recognized that different stakeholders may provide information about the same factor that is contradictory and allowed transmission providers to weigh more heavily one source of information over another.[957]

ii. Requests for Rehearing and Clarification

338. NESCOE requests clarification that transmission providers must rely on states in developing Long-Term Scenarios where state laws, regulations, and/or policies are driving Long-Term Transmission Needs. If the Commission does not provide this clarification, NESCOE requests rehearing.[958] NESCOE explains that state officials have expertise in connection with these matters such that transmission providers should rely on states for input regarding the details of state requirements in Factor Categories One, Two, and Seven. NESCOE claims that, in the absence of this clarification, transmission providers may devote resources to developing Long-Term Scenarios that are less useful to transmission planning regions.[959] Similarly, PJM States request clarification of the degree to which transmission providers should defer to, weigh, or consider the input of states as it relates specifically to state laws and integrated resource plans. PJM States argue that states have a unique role as to these subjects, and that transmission providers should not treat state perspectives the same as those of any other stakeholder.[960]

339. PIOs request rehearing such that the Commission would strengthen the transparency provisions by requiring transmission providers to provide more detailed explanations of the factors to be used and to justify any discounting of factors in Factor Categories Four through Seven. PIOs argue that stronger transparency provisions would foster more meaningful stakeholder processes.[961] Specifically, PIOs contend that, with respect to the information that transmission providers must publish on the public portion of an OASIS or other public website, the Commission should replace the third item, *i.e.,* ''a general statement explaining how [transmission providers] will account for each of [the factors that they will account for in their Long-Term Scenarios],'' with ''a detailed description of the reasoning and methodology used to account for each factor, as well as providing the actual data inputs when possible.'' [962]

340. PIOs criticize the Commission's rationale for declining to include this requirement, *i.e.,* that the burden would not be justified by the benefit of such additional information. PIOs argue that requiring transmission providers to justify their discounting decisions would help hold transmission providers accountable, incentivize more accurate discounting assumptions, and guard against pressure from self-interested stakeholders to excessively discount factors.[963] PIOs contend that Order No. 1920 is arbitrary and capricious because failing to require more detailed explanations of the factors to be used or to justify any discounting of factors in Factor Categories Four through Seven does not flow rationally from Order No. 1920's ''more fundamental findings'' as to the requirements for transmission providers to provide meaningful opportunity for stakeholder input and to make the development of Long-Term Scenarios transparent.[964]

341. SERTP Sponsors request that the Commission clarify that transmission providers have the discretion to include or to exclude an assumption from the development of a Long-Term Scenario where stakeholders do not provide transmission providers with sufficient information as to whether a potential assumption or factor is likely to affect Long-Term Transmission Needs. SERTP Sponsors provide the example of a generator whose point of interconnection is unknown and contend that transmission providers should not be obligated to hypothesize arbitrarily as to that point of interconnection, because doing so likely would yield implausible Long-Term Scenarios and would not result in cost-effective or efficient transmission planning.[965]

342. SERTP Sponsors request that the Commission clarify that transmission providers may rely on stakeholders to identify factors in Factor Categories Four through Seven, and, if stakeholders identify no such factors, that transmission providers may but need not do so. SERTP Sponsors contend that Order No. 1920 implies but does not clearly provide for this requested clarification.[966] SERTP Sponsors also request that the Commission clarify that transmission providers may rely upon stakeholders to identify factors that, unlike factors in Factor Categories One through Three, do not pertain directly to a specific transmission provider in the relevant transmission planning region.[967] If the Commission does not so clarify, SERTP Sponsors request rehearing on the grounds that requiring transmission providers to identify such factors would be unduly burdensome.[968]

343. Finally, SERTP Sponsors request that the Commission clarify the required timing of when transmission providers must publish on the public portion of an OASIS or other public website the information about factors required by Order No. 1920. SERTP Sponsors contend that Order No. 1920 does not make clear whether this information must be published in conjunction with transmission providers' compliance filings or by the start of the first Long-Term Regional Transmission Planning cycle. SERTP Sponsors argue that the Commission should require transmission providers to post this information after the conclusion of the period during which stakeholders provide input into these matters.[969]

iii. Commission Determination

344. In response to NESCOE's and PJM States' requested clarification that transmission providers must rely on states in developing Long-Term Scenarios where state laws, regulations, and/or policies are driving Long-Term Transmission Needs, we grant the following clarifications. We clarify that states must have a meaningful opportunity to provide timely input on the development of Long-Term Scenarios, including factors and data inputs, and to explain how their own policies and planning affect Long-Term Transmission Needs.[970] Furthermore, we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios.[971] Specifically, transmission

[956] *Id.* P 530.

[957] *Id.* P 531.

[958] NESCOE Rehearing Request at 11.

[959] *Id.* at 20–21.

[960] PJM States Rehearing Request at 4.

[961] PIOs Rehearing Request at 36.

[962] *Id.*

[963] *Id.* at 37–38.

[964] *Id.* at 38 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 305).

[965] SERTP Sponsors Rehearing Request at 13–14.

[966] *Id.* at 13 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 516).

[967] *Id.* at 14 & n.33.

[968] *Id.* at 14.

[969] *Id.* at 26.

[970] Order No. 1920, 187 FERC ¶ 61,068 at PP 528–537, 560–562, 634.

[971] A Relevant State Entity may believe that a different state entity would be better situated to advise transmission providers as to how state policy may affect Long-Term Transmission Needs. For example, the state entity responsible for electric utility regulation may believe that the state entity responsible for energy policy is in a better position to advise on state energy policy implementation. In

providers shall consult with Relevant State Entities and any other authorized entities as to whether a specific state policy must be accounted for as a factor within each category (*i.e.,* if the specific state policy will likely affect Long-Term Transmission Needs), how to account for the specific state policy in the development of Long-Term Scenarios (*e.g.,* the method and data used to forecast generation resources added because of a specific state policy), and how to adjust the treatment of the specific state policy across Long-Term Scenarios (*e.g.,* assume certain policy-related outcomes materialize in some but not all Long-Term Scenarios).[972]

345. We further clarify that, where transmission providers determine that a factor based on a state's law, regulation, or policy is likely to affect Long-Term Transmission Needs, transmission providers should rely on the state in determining *how* to account for such a state-related factor when developing Long-Term Scenarios. For example, for a state that has required integrated resource planning processes, transmission providers should include one of the state's preferred power system trajectories, including both the supply and demand side resource trajectory as appropriate, in each of Long-Term Scenarios, or include different state-preferred power system trajectories in different Long-Term Scenarios. As such, transmission providers could include in the development of Long-Term Scenarios the set of resource capacity additions and/or retirements expected by a state based on the incentives or requirements in that state's law. If transmission providers determine, based on input provided by the state or their own judgment, that a factor based on a state's law, regulation, or policy is likely to affect Long-Term Transmission Needs, transmission providers should then determine whether and how to account for that factor in the development of Long-Term Scenarios.

346. We disagree with PIOs that a more detailed explanation of the factors that transmission providers will account for in their Long-Term Scenarios and justification of the factors that they will discount is warranted. Broadly, we affirm that Order No. 1920 strikes the right balance between prescriptive requirements and flexibility with respect to the development of Long-Term Scenarios.[973] We also find that this is true with respect specifically to Order No. 1920's requirements on stakeholder process and transparency. PIOs request that we require ''a detailed description of the reasoning and methodology used to account for each factor, as well as providing the actual data inputs when possible'' and that we require transmission providers to justify their discounting decisions of factors in Factor Categories Four through Seven. We find that such requirements are not necessary to ensure that stakeholders have a meaningful opportunity to provide input. We further find that the requirements of Order No. 1920 ensure that the development of Long-Term Scenarios is sufficiently transparent,[974] and that PIOs' requested requirements are not needed to ensure that transmission providers use accurate data.[975]

347. We emphasize that Order No. 1920 sets minimum requirements with which all transmission providers must comply, and we are not convinced that the level of information that PIOs seek is necessary. Further, we clarify that nothing in Order No. 1920 prevents transmission providers from providing more than the minimum amount of information that we require, including the level of detail requested by PIOs. Moreover, we conclude that granting PIOs' request is unnecessary because the existing transparency requirements in Order No. 1920[976] are sufficient to ensure that ''the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario'' are transparent.[977]

348. We decline to provide clarification to SERTP Sponsors with respect to the inclusion or exclusion of factors for which stakeholders provide insufficient information, and we similarly decline to address SERTP Sponsors' hypothetical in the abstract.[978] Generally, transmission providers can rely on stakeholders for input on the development of Long-Term Scenarios, including factors and data inputs, and must consult with and consider the positions of Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative regarding how their policies and planning affect Long-Term Transmission Needs and the assumptions that will be used in the development of Long-Term Scenarios. Transmission providers implementing Long-Term Regional Transmission Planning necessarily will balance competing interests from within the transmission planning region when developing Long-Term Scenarios, and Order No. 1920 provides transmission providers with sufficient flexibility to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements.[979]

349. In response to SERTP Sponsors' request for clarification regarding the identification of factors in Factor Categories Four through Seven, we clarify that transmission providers must identify factors in Factor Categories Four, Five, and Six but need not independently identify factors in Factor Category Seven—rather, transmission providers may rely on stakeholders, including states, to bring such factors to their attention. We believe that factors in Factor Categories One, Two, Three, and Seven arise from stakeholder decision-making and legal processes that generally are external to the transmission provider and are therefore suitable for identification by the states and other stakeholders that govern or have authority over those processes. Therefore, as with factors in Factor Categories One, Two, and Three, transmission providers may rely on stakeholders to identify factors in Factor Category Seven in the development of Long-Term Scenarios, particularly through the open and transparent stakeholder process required by Order No. 1920.[980] In contrast, we believe that

this case, the Relevant State Entity may authorize the other state entity as its representative in discussions with transmission providers.

[972] *See id.* P 417.

[973] *Id.*

[974] *See id.* P 533 (requiring transmission providers to publicly post ''(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.'').

[975] PIOs Rehearing Request at 36–37. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 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.'').

[976] *Supra* P 346 n.975.

[977] Order No. 1920, 187 FERC ¶ 61,068 at P 305.

[978] It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[979] Order No. 1920, 187 FERC ¶ 61,068 at P 1027.

[980] *Id.* P 508. We note, however, an exception to this general rule. Where the transmission provider is the entity that has made a commitment that affects Long-Term Transmission Needs, the transmission provider may not rely on the

Continued

factors in Factor Categories Four, Five, and Six relate to the expertise of transmission providers arising from their day-to-day operations. For example, transmission providers manage processes for processing interconnection requests and withdrawals (Factor Category Six) and determining the impact of resource retirements (Factor Category Five). In managing those processes and the day-to-day operations of the transmission system, transmission providers also gain information about trends in technology and fuel costs within and outside the electricity supply industry (Factor Category Four). Therefore, we clarify that transmission providers have an independent obligation to identify factors in Factor Categories Four, Five, and Six regardless of whether any such factors are identified by stakeholders and must, where relevant, consult with and consider the positions of Relevant State Entities and any entities authorized by the Relevant State Entities. In response to SERTP Sponsors' argument that, if transmission providers must independently identify factors in Factor Categories Four through Seven, the Commission would be holding transmission providers to a burdensome unattainable standard, we clarify that the independent obligation to identify factors in Factor Categories Four through Six does not require transmission providers to identify every potentially knowable factor within those categories. Transmission providers can use their prior experience and professional judgement to independently identify factors in Factor Categories Four, Five, and Six.

350. Finally, in response to SERTP Sponsors' request for clarification regarding the timing of transmission providers' publication of information regarding the factors to be incorporated into the development of Long-Term Scenarios on the public portion of an OASIS or other public website, we clarify that transmission providers do not need to include this information with the filings that they submit to comply with Order No. 1920. Rather, we clarify that Order No. 1920 requires transmission providers to post this information as part of each Long-Term Regional Transmission Planning cycle after stakeholders, including states, have had 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 for that planning cycle.[981] We further clarify that publication of information regarding the factors to be incorporated into the development of Long-Term Scenarios must occur before transmission providers finish developing Long-Term Scenarios,[982] and, in any event, well before the transmission provider has identified Long-Term Transmission Needs.

identification by stakeholders of this factor or these factors.

5. Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements

351. This section responds to requests for rehearing or clarification to permit additional flexibility with respect to multiple interrelated Long-Term Scenario requirements, including transmission providers' incorporation of factors from seven categories of factors; the treatment of factors in the first three categories of factors; and the number, type, and plausibility of Long-Term Scenarios.

a. Order No. 1920 Requirements

352. In Order No. 1920, the Commission required transmission providers in each transmission planning region to 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.[983] The Commission adopted the NOPR proposals to require transmission providers in each transmission planning region to publicly disclose information and data inputs used to create each Long-Term Scenario and provide stakeholders an opportunity to provide timely and meaningful input into how Long-Term Scenarios are developed.[984]

353. The Commission required transmission providers in each transmission planning region to develop a plausible and diverse set of at least three Long-Term Scenarios.[985] The Commission also required that each individual Long-Term Scenario be plausible to avoid resting on assumptions about factors and data inputs that do not reasonably capture possible future outcomes. The Commission clarified that the term ''diverse'' means 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.[986]

354. The Commission also required 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.[987] In Order No. 1920, the Commission provided 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.[988] Order No. 1920 did not preclude transmission providers from considering additional sensitivities, and the Commission encouraged transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.[989] The Commission found that modeling extreme weather events as sensitivities is appropriate for Long-Term Regional Transmission Planning.[990]

b. Requests for Rehearing and Clarification

355. PJM requests rehearing such that the Commission either would consider requests for flexibility or permit flexibility that PJM contends would be required for PJM to develop Long-Term Scenarios and sensitivities consistent with a draft long-term transmission planning process that PJM has developed.[991] PJM argues that Order No.

[981] *Id.* P 533.

[982] *See id.* P 534 (discussing the value of posting requirement in terms of the transparency into how transmission providers develop Long-Term Scenarios).

[983] *Id.* P 559.

[984] *Id.* P 560.

[985] *Id.* PP 575–577.

[986] *Id.* P 576.

[987] *Id.* P 593.

[988] *Id.* P 594.

[989] *Id.* P 597.

[990] *Id.* P 598.

[991] *See* PJM Rehearing Request at 12 (''Granting rehearing and permitting flexibility with respect to the issues identified below would allow PJM to use the PJM Long Term Regional Transmission Planning process as the foundation for a long-term planning process that achieves the objectives of the Final Rule, even though implementation details may differ in some way from those the Final Rule prescribes.'' (footnote omitted)); *id.* at 14 (''PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to accommodate regional differences.''); *id.* at 19 (''[G]iven the diversity among regions, PJM believes it is appropriate to allow transmission planners to work with states and stakeholders within their respective regions to determine the appropriate number of and specific scenarios to be used in the Long-Term Regional Transmission Planning process, as well as giving the transmission provider flexibility to determine how to weigh specific factors used to develop the assumptions upon

1920's requirements with respect to the development of Long-Term Scenarios are overly prescriptive, particularly with respect to the requirements that transmission providers develop three Long-Term Scenarios that each incorporate seven categories of factors and that transmission providers cannot discount factors in Factor Categories One through Three.[992] PJM contends that these requirements would ''complicate'' PJM's efforts to promote more efficient or cost-effective regional transmission planning and development.[993]

356. PJM explains that, under the draft long-term transmission planning process that PJM developed, PJM would develop three distinct scenarios that would ''generally account for the seven factors'' required by Order No. 1920: the ''Base Reliability Scenario,'' the ''Medium Public Policy Scenario,'' and the ''High Public Policy Scenario.'' [994] The Base Reliability Scenario would include certain ''categories of factors,'' including: the PJM Load Forecast Report; announced retirements and retirements required by Public Policy Requirements; in-service generation and generation that is not yet in service but with an executed service agreement or State Agreement Approach reservation; and replacement generation taken mainly from the PJM Service Request process.[995] The Medium Public Policy Scenario would build on the Base Reliability Scenario by including certain additional Public Policy Requirements that otherwise would be brought to PJM as part of the State Agreement Approach process, such as state renewable portfolio standards.[996] The High Public Policy Scenario would in turn build on the Medium Public Policy Scenario by modeling ''Public Policy Objectives,'' defined as Public Policy Requirements that are not yet in a statute or regulation.[997] PJM argues that this draft process would demonstrate a wide range of possible transmission needs, and would be a prudent way to account for long-term needs without overbuilding the transmission system.[998]

357. PJM States and West Virginia Commission request that the Commission clarify that—or, in the alternative, request rehearing such that—Order No. 1920 does not prohibit the development by transmission providers of a fourth Long-Term Scenario or additional sensitivities that are designed to provide information to states on the factors driving the need for transmission facilities and on their costs and benefits. PJM States and West Virginia Commission explain that Order No. 1920 requires that transmission providers assume that all legally binding obligations are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are met and not discounted. PJM States and West Virginia therefore express concern that Order No. 1920 places ''undue restrictions'' on the development of scenarios or sensitivities that can provide the information sought by states, which PJM States contend would be necessary to assist in cost allocation determinations and in siting and safety decisions.[999]

358. Ohio Commission Federal Advocate argues that Order No. 1920 makes it impossible to identify and evaluate transmission facilities that are required due to other states' laws, as well as to ''isolate the incremental costs'' arising from those laws. Ohio Commission Federal Advocate states that this lack of transparency is not in the public interest, and that the Commission should clarify that counterfactual scenarios that do not reflect compliance with state law are permissible because they provide important insights into the factors driving transmission needs.[1000]

359. Virginia and North Carolina Commissions argue that the Commission should grant rehearing such that Order No. 1920 would require or allow for one or more ''baseline'' planning scenarios that exclude all or some policy-driven factors. Virginia and North Carolina Commissions explain that Order No. 1920 requires transmission providers to incorporate seven categories of factors in each Long-Term Scenario, and that the Commission did not allow flexibility for additional scenarios that exclude some or all of these factors. Virginia and North Carolina Commissions contend that, without a ''baseline'' scenario, Relevant State Entities and other stakeholders will not have adequate transparency regarding the critical drivers of transmission needs or the costs associated with a particular transmission facility, nor will they be able to evaluate whether cost allocation methods comply with the Commission's cost causation principles.[1001]

360. Finally, in PJM's general request for additional flexibility in the development of Long-Term Scenarios, PJM identified the requirement in Order No. 1920 to conduct a specific sensitivity for each Long-Term Scenario as an example of a requirement that it believes to be overly burdensome.[1002] PJM States and West Virginia Commission request that the Commission clarify that—or grant rehearing such that—transmission providers are required, or even permitted, to provide additional sensitivity analyses to the states that best inform them on required transmission facility needs, costs, and benefits based on variations or exclusions of specific factors or categories of factors, including those in the first three categories of factors.[1003]

c. Commission Determination

361. We disagree with PJM's rehearing arguments and deny its requested clarification with respect to flexibility regarding the development of Long-Term Scenarios. Specifically, we continue to find that transmission providers must develop at least three distinct Long-Term Scenarios as defined in Order No. 1920, and that transmission providers must incorporate the seven categories of factors set forth in Order No. 1920 into each of those Long-Term Scenarios,[1004] as also clarified above.[1005] As the Commission held in Order No. 1920, and as we continue to find here, the Commission's regional transmission planning requirements currently fail to adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs, and the incorporation of the seven categories of factors is necessary because these categories of factors are essential to identifying Long-Term Transmission Needs.[1006] Failing to require that transmission providers incorporate these categories of factors into the

which Long-Term Scenarios are based.''); *id.* (''PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to develop Long-Term Scenarios and conduct sensitivity analyses in such a way as to accommodate regional differences.'').

[992] *Id.* at 13 n.59, 16, 18.

[993] *Id.* at 16, 18.

[994] *Id.* at 16–18.

[995] *Id.* at 16–17.

[996] *Id.* at 17–18.

[997] *Id.* at 18 & n.80.

[998] *Id.* at 19.

[999] PJM States Rehearing Request at 4–6; West Virginia Commission Rehearing Request at 14–16.

[1000] Ohio Commission Federal Advocate Rehearing Request at 18.

[1001] Virginia and North Carolina Commissions Rehearing Request at 4–5.

[1002] PJM Rehearing Request at 16.

[1003] PJM States Rehearing Request at 4–5; West Virginia Commission Rehearing Request at 14–16.

[1004] Order No. 1920, 187 FERC ¶ 61,068 at PP 409, 559.

[1005] *See supra* Long-Term Scenarios Requirements, Stakeholder Process and Transparency section.

[1006] Order No. 1920, 187 FERC ¶ 61,068 at P 410.

development of each Long-Term Scenario 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.[1007]

362. We also continue to find that transmission providers must 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.[1008] Each Long-Term Scenario must account for and be consistent with factors in these first three categories of factors, because these categories of factors are part of the primary drivers of Long-Term Transmission Needs.[1009]

363. We disagree with PJM's apparent contention that complying with Order No. 1920 requirements with respect to Long-Term Scenarios will ''complicate'' PJM's efforts to conduct Long-Term Regional Transmission Planning[1010] as it is set forth in Order No. 1920.[1011] Instead, we reiterate that Order No. 1920's Long-Term Scenarios requirements strike a reasonable balance between, on the one hand, ensuring that transmission providers identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities that would meet those needs, and, on the other hand, 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.[1012] We continue to find that Order No. 1920's categories of factors requirements strike the right balance between prescriptive requirements and flexibility[1013] and that they are sufficiently detailed to address the need for reform without limiting regional flexibility.[1014] Further, we continue to find that the requirement to develop at least three distinct Long-Term Scenarios that meet Order No. 1920's requirements 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.[1015]

364. In response to the requests for clarification and/or rehearing of various Order No. 1920 requirements related to Long-Term Scenarios and sensitivities submitted by PJM States, Virginia and North Carolina Commissions, Ohio Commission Federal Advocate, and West Virginia Commission, we clarify that Order No. 1920 allows transmission providers to conduct analyses in addition to those required by Order No. 1920—including additional scenarios or sensitivities[1016]—at the transmission providers' discretion or at the request of the transmission planning region's Relevant State Entities and/or other stakeholders.

365. Specifically, we clarify that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es). We believe that additional analyses may help transmission providers and stakeholders to better understand the potential impact of Long-Term Regional Transmission Facilities on the transmission system, as well as the costs and benefits of Long-Term Regional Transmission Facilities. Particularly, consistent with the flexibility the Commission provided in Order No. 1920 as to cost allocation methods for Long-Term Regional Transmission Facilities (or portfolios of such Facilities), we find that additional analyses may help inform the application of *ex ante* Long-Term Regional Transmission Cost Allocation Methods or the development of cost allocation methods through the State Agreement Process.

366. We further clarify that, when developing these additional analyses or scenarios used to inform cost allocation, transmission providers have the flexibility to depart from Order No. 1920's requirements related to the development of Long-Term Scenarios. For example, transmission providers may develop scenarios that consider the incremental cost and benefits of Long-Term Regional Transmission Facilities needed to achieve state laws, policies, and regulations beyond the cost and benefits of Long-Term Regional Transmission Facilities needed in the absence of those laws, policies, and regulations. Finally, as discussed below, we clarify that, if the Relevant State Entities wish for the transmission provider to develop a reasonable number of additional scenarios for Long-Term Regional Transmission Planning or Long-Term Regional Cost Allocation, then the transmission providers will develop these scenarios. While transmission providers may conduct such additional analyses, additional analyses that do not meet Order No. 1920's Long-Term Scenario requirements are not considered Long-Term Scenarios as defined in Order No. 1920.[1017] In other words, transmission providers may not use any such additional analyses to identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities, or to meet the requirement that transmission providers estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities for purposes of selection (*i.e.,* to apply the transmission provider's selection criteria). Transmission providers also may not, consistent with the requirement that transmission providers have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs, condition the selection of a Long-Term Regional Transmission Facility on the information provided in these additional analyses.

367. Next, we clarify that, when requested by Relevant State Entities in a transmission planning region, transmission providers are required to conduct a reasonable number of additional analyses or scenarios. On

[1007] *Id.* P 411.

[1008] We continue to find that it is appropriate for transmission providers to assume that legally binding obligations are met, unless and until there is a change in law. *Id.* P 512.

[1009] *Id.* PP 507, 512.

[1010] PJM Rehearing Request at 18–19.

[1011] To the extent that PJM was requesting that the Commission address in this order PJM's proposed long-term transmission planning process, we decline to address such a request here because doing so would be premature and more properly the subject of compliance.

[1012] Order No. 1920, 187 FERC ¶ 61,068 at P 298.

[1013] *Id.* P 417.

[1014] *Id.* P 421.

[1015] *Id.* P 559.

[1016] The use of ''scenarios'' in this context indicates that these analyses are not required to meet Order No. 1920's requirements as to the development of Long-Term Scenarios and therefore are not ''Long-Term Scenarios'' within the meaning provided in Order No. 1920.

[1017] Generally, to comply with Order No. 1920, including as clarified herein, transmission providers must develop at least three Long-Term Scenarios and perform at least one sensitivity analysis for each such Long-Term Scenario; identify Long-Term Transmission Needs using those Long-Term Scenarios and sensitivities thereto; identify Long-Term Regional Transmission Facilities (or portfolios of Long-Term Regional Transmission Facilities) that meet the identified Long-Term Transmission Needs; use and measure the seven required benefits of Long-Term Regional Transmission Facilities within those Long-Term Scenarios and sensitivities; otherwise evaluate those Long-Term Regional Transmission Facilities in the manner prescribed by Order No. 1920; and make a selection decision as to the Long-Term Regional Transmission Facilities identified and evaluated by transmission providers.

compliance, transmission providers may propose processes to determine when Relevant State Entities have requested additional analyses and how to determine what a reasonable number of additional analyses may be.[1018] We reiterate that any cost allocation method—whether an *ex ante* Long-Term Regional Transmission Cost Allocation Method or a cost allocation method developed through the State Agreement Process for a specific Long-Term Regional Transmission Facility or portfolio thereof— that results from such additional analyses or scenarios must satisfy the cost causation principle.[1019]

368. Finally, in response to the request for rehearing from PJM related to sensitivity analyses required by Order No. 1920 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, we disagree with the arguments on rehearing and decline to provide clarification. We continue to find that Order No. 1920's requirements in this regard are necessary to ensure just and reasonable Commission-jurisdictional rates. In particular, extreme weather events have occurred more frequently in recent years, represent periods during which regional transmission facilities have particularly high value, and create stressed system conditions that transmission providers can readily compare with non-stressed scenarios to determine the value of specific transmission facilities under these types of conditions.[1020] PJM did not provide adequate information to explain why additional flexibility in developing sensitivities for each Long-Term Scenario is necessary, and we are unconvinced that PJM's regional circumstances justify flexibility on this issue. To the extent that PJM's regional circumstances require other specific sensitivities, we reiterate that we encourage transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.[1021]

C. Evaluation of the Benefits of Regional Transmission Facilities

1. Requirement for Transmission Providers To Use and Measure a Set of Seven Required Benefits

a. Order No. 1920 Requirements

369. In Order No. 1920, the Commission required 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 and to use these measured benefits to evaluate Long-Term Regional Transmission Facilities.[1022] The Commission required transmission providers to measure and use the following required benefits in Long-Term Regional Transmission Planning: (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.[1023]

370. The Commission found that the record demonstrated that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it was 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. Further, the Commission found 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 could not be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.[1024] The Commission concluded that requiring the measurement and use of the seven required benefits in Long-Term Regional Transmission Planning ensured 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, the Commission found that not requiring transmission providers to use any specific benefits in Long-Term Regional Transmission Planning, as proposed in the NOPR, 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(s) to specific Long-Term Transmission Needs.[1025]

371. The requirement that transmission providers measure and use the required benefits in Long-Term Regional Transmission Planning was a change from the NOPR proposal.[1026] In the NOPR, the Commission did not propose to require the use of any specific benefits and instead acknowledged the benefits of regional flexibility, and consistent with Order No. 1000, proposed to consider such matters on review of compliance proposals.[1027] The NOPR included a non-exhaustive list of 12 benefits[1028] that the Commission stated could be considered by transmission providers in Long-Term Regional Transmission Planning and cost allocation processes.[1029] The Commission also sought comment on ''whether public utility transmission providers should be required to use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process.''[1030]

[1018] For example, in Order No. 890, the Commission required that stakeholders be given the right to request that transmission providers conduct a certain number of economic planning studies, to be determined on a regional basis, and the Commission offered the ''merely illustrative'' example of five to ten such studies. Order No. 890, 118 FERC ¶ 61,119 at P 547 & n.323.

[1019] Order No. 1920, 187 FERC ¶ 61,068 at PP 1472, 1477.

[1020] *Id.* P 596. *See also Transmission Sys. Plan. Performance Requirements for Extreme Weather,* Order No. 896, 88 FR 41262 (June 23, 2023), 183 FERC ¶ 61,191, at P 2 (2023) (explaining that extreme heat and cold weather events have occurred more frequently in recent years); *One-Time Informational Reps. on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, & Elec. Sys. Reliability,* Order No. 897, 88 FR 41477 (June 27, 2023), 183 FERC ¶ 61,192, at P 2 (2023) (same).

[1021] Order No. 1920, 187 FERC ¶ 61,068 at P 597.

[1022] Order No. 1920, 187 FERC ¶ 61,068 at P 719.

[1023] *Id.* P 720.

[1024] *Id.* P 722.

[1025] *Id.* P 723.

[1026] *Id.*

[1027] NOPR, 179 FERC ¶ 61,028 at P 183 (citation omitted).

[1028] *Id.* P 185.

[1029] *Id.* P 184.

[1030] *Id.* P 188.

b. Logical Outgrowth

i. Requests for Rehearing and Clarification

372. East Kentucky and NRECA argue that Order No. 1920 violates the APA's notice-and-comment requirements because it mandates that transmission providers use a set of seven benefits for evaluating Long-Term Regional Transmission Facilities, a requirement that East Kentucky and NRECA argue is not a logical outgrowth of the NOPR, which proposed non-mandatory and non-exhaustive examples of benefits that transmission providers could use.[1031] NRECA asserts that the NOPR made clear that the list of potential benefits was neither mandatory nor exhaustive and that transmission providers would have flexibility to determine what benefits they use in their Long-Term Regional Transmission Planning.[1032] NRECA describes the final rule's seven required benefits as ''nationwide, mandatory, [and] one-size-fits all'' and the ''exact opposite'' of the proposed rule.[1033]

ii. Commission Determination

373. We disagree with the argument that the Commission failed to provide adequate notice and opportunity to comment on Order No. 1920's requirement that transmission providers measure a set of seven required benefits for Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of Long-Term Regional Transmission Planning and use these measured benefits to evaluate Long-Term Regional Transmission Facilities.[1034] As courts have explained, ''[n]otice suffices when [an agency] has 'expressly asked for comments on a particular issue or otherwise made clear that the agency was contemplating a particular change.' '' [1035] NRECA acknowledges that the NOPR 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.[1036] By requesting comment on whether to make mandatory some or all of the benefits in the NOPR, the Commission sufficiently put parties on notice that the Commission was considering *the exact change* that East Kentucky and NRECA now argue was unanticipated and violated the APA's notice-and-comment requirements. Thus, in adopting the requirement that transmission providers measure and use the set of seven required benefits in Long-Term Regional Transmission Planning, the Commission adhered to the APA's notice-and-comment requirements.

c. Flexibility Regarding Benefits Rather Than a Minimum Set

i. Requests for Rehearing and Clarification

374. Dominion requests rehearing and argues that the seven required benefits are not directly tied or correlated to the seven categories of factors establishing Long-Term Transmission Needs.[1037] Dominion contends that the seven required benefits ''are generic, almost inherent benefits of all transmission,'' whereas the seven categories of factors that transmission providers must incorporate in the development of Long-Term Scenarios ''are mostly restatements of public policy driven needs for transmission facilities.'' [1038] Dominion states that it ''is not suggesting that Factor Category No. 1 must match Benefit No. 1, etc.; rather, individually, and as a whole, the[] seven Factor Categories do not correlate to any or all of the seven Benefits.'' [1039] Dominion opines that, because the seven required benefits do not correspond to the seven categories of factors, regardless of the public policy issues driving the need for a transmission facility, Order No. 1920's requirement that transmission providers use the seven required benefits in determining whether to select a transmission facility will likely result in a public policy project always being selected.[1040] Further, Dominion opines that, because the seven required benefits do not correspond to the seven categories of factors, the seven required benefits are ''secondary or incidental'' to the primary purpose of the Long-Term Regional Transmission Facilities. Dominion states that the United States Court of Appeals for the Seventh Circuit ''rejected the use of 'incidental' benefits because 'the incidental-benefits tail mustn't be allowed to wag the primary-benefits dog.' '' [1041] Dominion contends that Order No. 1920 should have required that Long-Term Transmission Needs and the benefits of Long-Term Regional Transmission Facilities correspond to each other, and failure to impose such a requirement was not reasoned decision making.[1042] Dominion states that the Commission should provide flexibility to transmission providers to allow them to identify the benefits that they will measure in their compliance filings and ensure that those benefits are tied to the underlying needs.[1043]

375. PJM requests rehearing and argues that Order No. 1920 is arbitrary and capricious because the requirement that transmission providers measure and use seven required benefits to evaluate Long-Term Regional Transmission Facilities is an unexplained departure from the NOPR's recognition of the value of allowing regional flexibility with respect to benefits.[1044] PJM argues that the Commission should provide flexibility to transmission providers to allow them to identify the benefits that they will measure in their compliance filings (except for Final Rule Benefits 1, 2, and 3, which PJM agrees should be required).[1045] PJM asserts that Final Rule Benefits 4 and 5 are additional benefits that RTOs could add as they gain experience and determine to be quantitatively important. PJM also argues that Final Rule Benefit 6 has three different subcomponents and could be very cumbersome to measure if each one of them must be quantified.[1046]

376. Designated Retail Regulators and Undersigned States request rehearing and assert that the benefit metrics used to evaluate Long-Term Regional Transmission Facilities should be developed as part of RTO stakeholder processes, not mandated by the Commission.[1047] NRECA alleges that by prescribing the required benefits that transmission providers must use for evaluation and selection of Long-Term Regional Transmission Facilities, the final rule will likely change the results of the evaluation and selection processes in unanticipated ways.[1048]

[1031] East Kentucky Rehearing Request at 1–2 (citing 5 U.S.C. 553(b)); NRECA Rehearing Request at 4, 10–13 (citing 5 U.S.C. 553(b)).

[1032] NRECA Rehearing Request at 10 (quoting NOPR, 179 FERC ¶ 61,028 at P 183).

[1033] *Id.* at 11.

[1034] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 719.

[1035] *Brennan* v. *Dickson,* 45 F.4th 48, 69 (D.C. Cir. 2022) (quoting *CSX Transp., Inc.* v. *Surface Transp. Bd.,* 584 F.3d 1076, 1081 (D.C. Cir. 2009)).

[1036] *See* NRECA Rehearing Request at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 188).

[1037] Dominion Rehearing Request at 18.

[1038] *Id.* at 20.

[1039] *Id.* at 19 n.83.

[1040] *Id.* at 20.

[1041] *Id.* (alteration omitted) (quoting *ICC* v. *FERC III,* 756 F.3d at 564).

[1042] *Id.*

[1043] *Id.* at 18–19, 21.

[1044] PJM Rehearing Request at 5, 26–27 & n.106.

[1045] *Id.* at 26–29, 42.

[1046] *Id.* at 29.

[1047] Designated Retail Regulators Rehearing Request at 29; Undersigned States Rehearing Request at 29.

[1048] NRECA Rehearing Request at 11–12.

ii. Commission Determination

377. We are not persuaded by arguments raised on rehearing that the Commission should not require transmission providers to use and measure the seven required benefits. We continue to find that allowing transmission providers to determine which benefits they will use and measure, rather than requiring the measurement and use of a minimum set of benefits, may result in transmission providers not measuring important potential benefits of Long-Term Regional Transmission Facilities.[1049] This, in turn, would not resolve the deficiencies that the Commission identified in the final rule, such as transmission providers failing to adequately consider the benefits of regional transmission facilities and thereby not selecting the more efficient or cost-effective solutions, leading to unjust and unreasonable Commission-jurisdictional rates.[1050] Additionally, as the Commission noted in Order No. 1920, requiring transmission providers to measure and use a required set of benefits will help improve interregional transmission coordination among different transmission planning regions.[1051]

378. We disagree with Dominion's argument that Order No. 1920 does not constitute reasoned decision making or is arbitrary and capricious because the seven required benefits are not tied or correlated to the seven categories of factors that Order No. 1920 requires transmission providers to incorporate into the development of Long-Term Scenarios. We understand Dominion's argument to be that, even though Long-Term Regional Transmission Facilities address Long-Term Transmission Needs that are driven primarily by the incorporation of certain categories of factors that Dominion considers to be ''public policy issues,'' the required benefits, which Dominion contends are designed to measure a broader range of benefits of transmission facilities unrelated to public policy-related factors, will likely result in a public policy project always being selected. We disagree with this argument. We first note that Dominion provides only speculation that such a result will occur. As the Commission found in Order No. 1920, while state policies make up some of the drivers of Long-Term Transmission Needs, they do not comprise the entirety of those drivers.[1052] Accordingly, Long-Term Transmission Needs will be driven by factors (*e.g.,* resource retirements and trends in fuel costs) in addition to and unrelated to ''public policy issues,'' and Long-Term Transmission Facilities will likely be designed to address multiple Long-Term Transmission Needs. In any case, Order No. 1920 does not require that transmission providers select any particular Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria,[1053] which this order maintains on rehearing.[1054]

379. We disagree with Dominion's assertion that the seven required benefits are ''secondary or incidental'' to Long-Term Transmission Needs. As the Commission explained in Order No. 1920, the drivers of transmission needs are diverse and include, but are not limited to, grid reliability, changes in the resource mix, and increased demand for electricity.[1055] As discussed in the Requirement for Transmission Providers To Use the Seven Required Benefits To Help To Inform Their Identification of Long-Term Transmission Needs section above, we clarify in this order that Long-Term Transmission Needs as defined in Order No. 1920 are driven by both reliability and economic considerations and, as such, both reliability and economic considerations must inform transmission providers' identification of Long-Term Transmission Needs. The seven required benefits measure distinct, well-understood benefits of potential Long-Term Regional Transmission Facilities and are well supported in the record.[1056] Because the seven required benefits reflect many of the reliability and economic benefits that Long-Term Regional Transmission Facilities can provide, we disagree with Dominion that such benefits are secondary or incidental to Long-Term Transmission Needs. Further, the Commission noted in Order No. 1920 that, ''[w]e 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.'' [1057] The Commission also stated that ''[b]y 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.'' [1058]

380. Finally, the Commission found in Order No. 1920, and we continue to find here, that transmission providers must measure, at a minimum, this set of seven required benefits and then use them to evaluate Long-Term Regional Transmission Facilities in order to ensure just and reasonable rates.[1059] The Commission noted:

> 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,

[1049] Order No. 1920, 187 FERC ¶ 61,068 at PP 723–724.

[1050] *See id.* P 123 (''Failing to adequately identify and consider the benefits of [Long-Term Regional 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.''); *id.* P 723.

[1051] *Id.* P 729 (citations omitted).

[1052] *Id.* P 1478. The Commission recognized that state policy goals do not necessarily need to be given the same weight as state laws and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios because government entities have an interest and ability to ensure that the requirements of state laws and regulations are fully achieved. *Id.* PP 512, 516.

[1053] *Id.* P 1026 (citations omitted).

[1054] *See infra* No Selection Requirement section.

[1055] Order No. 1920, 187 FERC ¶ 61,068 at P 299. *See also id.* PP 39, 299 (defining Long-Term Transmission Needs as ''transmission needs identified through Long-Term Regional Transmission Planning by, among other things . . . running scenarios and considering the enumerated categories of factors'').

[1056] *Id.* P 724 (noting that the seven required benefits ''have a proven track record''); *id.* P 746 (Final Rule Benefit 1), PP 749–750 (Final Rule Benefit 2), P 761 (Final Rule Benefit 3), P 782 (Final Rule Benefit 4), P 784 (Final Rule Benefit 5), P 791 (Final Rule Benefit 6), P 812 (Final Rule Benefit 7); *see also id.* P 731 (''[A]ll 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.''); *id.* P 732 (explaining that the Commission has accepted the use of several of the seven benefits to evaluate transmission facilities and projects).

[1057] *Id.* P 722.

[1058] *Id.* P 723.

[1059] *Id.* P 721.

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.[1060]

381. Indeed, as Dominion concedes, the seven benefits that Order No. 1920 requires transmission providers to use and measure when evaluating Long-Term Regional Transmission Facilities are ''inherent benefits of all transmission.'' [1061]

382. In addition, we disagree with PJM's assertion that Order No. 1920 is arbitrary and capricious because the requirement that transmission providers measure and use seven required benefits to evaluate Long-Term Regional Transmission Facilities is an unexplained departure from the NOPR's recognition of the value of allowing regional flexibility with respect to benefits. We continue to find that the requirement for transmission providers to measure and use the minimum set of seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1062] Specifically, absent a requirement that transmission providers measure and use a sufficiently broad range of the 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. Therefore, we find that allowing the regional flexibility that PJM suggests would fail to remedy the deficiencies in existing regional transmission planning and cost allocation processes—namely, the failure to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs [1063]—that the Commission identified in the final rule.[1064] We also note that PJM itself previously recognized that certain benefits should be required; in its comments on the NOPR, PJM called for the adoption of a nationwide consideration of benefits that are similar to certain benefits that the Commission adopted in Order No. 1920 as part of the set of seven required benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning.[1065]

383. In response to Designated Retail Regulators' and Undersigned States' requests for flexibility to establish the benefits for transmission providers to measure through RTO/ISO stakeholder processes, we reiterate that the measurement and use of certain benefits in Long-Term Regional Transmission Planning is essential to ensuring just and reasonable Commission-jurisdictional rates.[1066] As such, we find that it is necessary for the Commission to mandate the measurement and use of these benefits—the required benefits—in Long-Term Regional Transmission Planning rather than deferring to RTO/ISO stakeholder processes.[1067]

384. We also are not persuaded by NRECA's assertion that, by prescribing the required benefits that transmission providers must use for evaluation and selection of Long-Term Regional Transmission Facilities, the final rule will likely change the results of the evaluation and selection processes in unanticipated ways. NRECA does not explain what unanticipated consequences it foresees arising, and we find this assertion speculative and unsupported.

d. Overlap and Double-Counting

i. Order No. 1920 Requirements

385. In Order No. 1920, the Commission noted that, ''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.'' [1068] In response to concerns raised by commenters regarding the potential for overlap and double-counting, the Commission further noted:

> 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.[1069]

386. With respect to Final Rule Benefit 3, Production Cost Savings, the Commission in Order No. 1920 explained why it did not believe that this benefit would result in double-counting of benefits merely because such benefits may also be considered in state resource planning.[1070] Specifically, the Commission found that while integrated resource planning processes, where they exist, may consider similar benefits compared to those required by Order No. 1920, 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.[1071]

387. The Commission in Order No. 1920 also offered guidance regarding the

[1060] *Id.* P 722.

[1061] Dominion Rehearing Request at 20.

[1062] Order No. 1920, 187 FERC ¶ 61,068 at P 727.

[1063] *Id.* P 122.

[1064] Contrary to PJM's assertion, in Order No. 1920 the Commission explained its reasons for not adopting the more flexible approach proposed in the NOPR. The Commission found:

> [A]dopting 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 rule 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.

Id. P 723; *see also id.* P 728 (''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 . . . 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.'').

[1065] PJM NOPR Initial Comments at 96 (''[T]he following benefit categories should be considered on a nationwide basis: (i) Enhanced Reliability; (ii) Avoided or Deferred Reliability Transmission Projects and Aging Infrastructure Replacement; (iii) Deferred Capacity Investment; and (iv) Production Cost Savings.'').

[1066] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 722–723, 725, 727–728.

[1067] *Id.* PP 723, 728.

[1068] *Id.* P 724.

[1069] *Id.* P 735.

[1070] *Id.* P 770.

[1071] *Id.*

manner of measurement of certain aspects of Final Rule Benefit 6, mitigation of extreme weather events and unexpected system conditions, to avoid double-counting. The Commission noted, for example, that ''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.'' [1072]

ii. Requests for Rehearing and Clarification

388. Designated Retail Regulators and Undersigned States request rehearing and assert that Order No. 1920's requirements to use seven required factors and seven required benefits will result in unjust and unreasonable rates. They argue that the seven required factors and seven required benefits overlap and will double-count or exaggerate the potential benefits of Long-Term Regional Transmission Facilities, with Undersigned States adding that this renders the rule arbitrary and capricious.[1073]

389. Designated Retail Regulators and Undersigned States assert that with respect to the seven required benefits, it is unclear whether these metrics will result in double-counting of potential benefits.[1074]

iii. Commission Determination

390. We disagree with Designated Retail Regulators and Undersigned States that the seven required benefits will overlap and will double-count or exaggerate the potential benefits of Long-Term Regional Transmission Facilities. As an initial matter, the Commission found in Order No. 1920, and we continue to find here, 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.'' [1075] Designated Retail Regulators and Undersigned States fail to provide evidence in support of their arguments to the contrary, and they do not provide any specific examples of the alleged overlap. Given the descriptions of the required benefits adopted in Order No. 1920,[1076] we conclude that each of these required benefits captures a different type of benefit that Long-Term Regional Transmission Facilities may provide. However, we reiterate, as the Commission stated in the final rule, that Order No. 1920 provides transmission providers with flexibility on the measurement of the required benefits, and we expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address any concerns about the possibility of double-counting benefits.[1077]

391. Moreover, the Commission explained in Order No. 1920 that transmission providers' evaluation of Long-Term Regional 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 Long-Term Regional Transmission Facilities) was selected or not selected.[1078] The Commission also explained that this determination must include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) that transmission providers evaluated in the Long-Term Regional Transmission Planning process, regardless of whether or not the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[1079] We find that these requirements will further safeguard against potential overlap and double-counting of benefits.

392. With respect to Undersigned States' and Designated Retail Regulators' concerns regarding the relationship between benefits and factors, we address this issue in the Requirement for Transmission Providers to Use the Seven Required Benefits to Help to Inform Their Identification of Long-Term Transmission Needs section above. As noted there, we are setting aside Order No. 1920's requirement for transmission providers to use the set of seven required benefits to help to inform their identification of Long-Term Transmission Needs. As such, we find that there is no overlap between the categories of factors that transmission providers must incorporate into the development of Long-Term Scenarios, which are developed prior to the identification of Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to address those needs, and the required benefits, which are subsequently used to evaluate the identified Long-Term Regional Transmission Facilities.

393. With respect to Designated Retail Regulators' and Undersigned States' concerns about potential overlaps between the seven required benefits and other benefits that transmission providers may use and measure, we find that Order No. 1920 provides for sufficient transparency to prevent any such overlap. Specifically, Order No. 1920 requires transmission providers to describe how they will measure the seven required benefits in OATT filings.[1080] Additionally, it requires transmission providers to measure and use any additional benefits beyond those included in the required set of benefits, including on a transmission facility or plan-specific basis, 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.[1081] As such, stakeholders will have the information necessary to identify any potential double-counting of the required benefits and any other benefits that transmission providers choose to measure and use in Long-Term Regional Transmission Planning.

e. Conflicts With State Authority

i. Requests for Rehearing and Clarification

394. Designated Retail Regulators assert that the seven required benefits conflict with the state authority reflected in both the transmission planning principles adopted by OMS that project metrics should be quantifiable, subject to accurate measurement, verifiable, non-duplicative, and forward looking and the Entergy Regional State Committee's adoption of ''even more stringent requirements to ensure that any metrics adopted reflected actual, not hypothetical, value that would justify major transmission investment.'' [1082]

[1072] *Id.* P 804.

[1073] Designated Retail Regulators Rehearing Request at 8 (citation omitted); Undersigned States Rehearing Request at 8 (citation omitted).

[1074] Designated Retail Regulators Rehearing Request at 29; Undersigned States Rehearing Request at 29.

[1075] Order No. 1920, 187 FERC ¶ 61,068 at P 735. As noted above, the Commission also addressed arguments relating to double-counting and/or overlap between Final Rule Benefit 3 and integrated resource planning processes and provided guidance regarding the manner of measurement of certain aspects of Final Rule Benefit 6, mitigation of extreme weather events and unexpected system conditions, to avoid double-counting.

[1076] *Id.* PP 745, 756, 758, 767, 781, 788, 800, 817.

[1077] *Id.* P 735.

[1078] *Id.* P 954.

[1079] *Id.* PP 954, 966.

[1080] *Id.* P 837.

[1081] *Id.* P 822.

[1082] Designated Retail Regulators Rehearing Request at 31–33 (citing Organization of MISO

Continued

For instance, Designated Retail Regulators state that the Entergy Regional State Committee (E–RSC) adopted stringent requirements to ensure that any metrics adopted reflected actual, not hypothetical, value that would justify major transmission investment:

The cost-benefit and other analyses that are used to inform the business case and cost allocation for Tranche 3 shall be based only on accurate, objective, measurable, quantifiable, non-duplicative, forward-looking, and replicable metrics that are supported by data;

Tranche 3 costs shall be allocated using an exclusive list of benefit metrics identified by the E–RSC, with advice from MISO and MISO South Stakeholders, that meet the criteria identified in Paragraph 3 above. These metrics shall be memorialized after being approved by the E–RSC;

Each Tranche 3 project must individually satisfy the cost-benefit analysis used for the business case and cost allocation on a stand-alone basis. Where two or more transmission facility upgrades combine to address a specific transmission issue, they may be evaluated as a single project for the purpose of analysis and cost allocation.[1083]

395. NESCOE requests that the Commission grant rehearing to require transmission providers to defer to states in the identification of benefits that Long-Term Regional Transmission Facilities may provide when the driver of the Long-Term Transmission Need is related to satisfying state laws, regulations, or policies.[1084]

ii. Commission Determination

396. We are not persuaded by requests for rehearing that argue that the Commission's establishment of a set of required benefits in Order No. 1920 impermissibly or improperly intrudes upon state authority. We continue to find that, while the Long-Term Regional Transmission Planning required in Order No. 1920 may be more 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 the appellate courts.[1085] Using the required benefits to evaluate Long-Term Regional Transmission Facilities is an incremental improvement to the Commission's Order No. 890 and Order No. 1000 reforms requiring processes for evaluating the merits of proposed transmission solutions offered by potential developers.[1086] The D.C. Circuit upheld the Commission's Order No. 1000 regional transmission planning reforms against challenges rooted in similar misunderstandings of the Commission's jurisdiction as those advanced by the rehearing parties.[1087]

397. Further, we reiterate the Commission's finding in Order No. 1920 that some benefits are so essential to Long-Term Regional Transmission Planning that they must be required and not left to the discretion of stakeholders, whether RTOs/ISOs or state committees.[1088] Order No. 1920, for example, found that requiring the measurement and use of Final Rule Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement, 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.[1089] Moreover, as discussed in the Flexibility Regarding Benefits Rather than a Minimum Set section above, the Commission found in Order No. 1920 that the requirement for transmission providers to measure and use the seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1090] We sustain this finding and, as a result, continue to find that the measurement and use of these minimum set of required benefits in Long-Term Regional Transmission Planning cannot be left to the discretion of transmission providers or stakeholders.

398. We also question the degree of intrusion cited by certain rehearing parties. We note, for example, that many of the OMS and Entergy Regional State Committee transmission planning principles cited by Designated Retail Regulators are similar to provisions governing the measurement and use of the required benefits in Order No. 1920. For example, Order No. 1920's findings and requirements with respect to the seven required benefits are consistent with the second of OMS's transmission planning principles[1091] that benefit metrics be quantifiable,[1092] capable of replication,[1093] non-duplicative,[1094] and forward-looking.[1095]

399. With respect to Designated Retail Regulators' assertions regarding the Entergy Regional State Committee requirements, we note that many of the metrics for analysis raised by the first cited requirement[1096] are similar to those required by the final rule and by OMS. With respect to the second requirement (''Tranche 3 costs shall be allocated using an exclusive list of benefit metrics identified by the E–RSC''), we note that transmission providers are free to measure and use additional benefits in Long-Term Regional Transmission Planning so long as they also measure and use the required benefits and measure and use any other benefits in a manner that is

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*).

[1083] Designated Retail Regulators Rehearing Request at 32–33 (quoting Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee,* 3 (adopted June 30, 2023), *https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf*).

[1084] NESCOE Rehearing Request at 11 (citation omitted).

[1085] Order No. 1920, 187 FERC ¶ 61,068 at P 277 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 68–69).

[1086] *See* Order No. 1000, 136 FERC ¶ 61,051 at 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).

[1087] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 63 (''Taken together, these points support the Commission's assertion of authority over transmission planning matters in the challenged orders, notwithstanding petitioners' contention that the orders intrude on the States' authority.'').

[1088] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 722–723, 725, 728.

[1089] *Id.* P 745.

[1090] *Id.* P 727.

[1091] 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.*

[1092] Order No. 1920, 187 FERC ¶ 61,068 at P 724 (''[W]e only require transmission providers to measure and use seven specific benefits that . . . can be discretely measured.'').

[1093] *Id.* P 837 (''[We] 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 . . . .'').

[1094] *Id.* P 735 (''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.'').

[1095] *Id.* P 859 (''[We] 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 . . . .'').

[1096] Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee,* at 3 (adopted June 30, 2023), *https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf* (''The cost-benefit and other analyses that are used to inform the business case and cost allocation for Tranche 3 shall be based only on accurate, objective, measurable, quantifiable, non-duplicative, forward-looking, and replicable metrics that are supported by data.'').

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.[1097] With respect to the third requirement,[1098] the final rule noted the potential to use cost-benefit metrics as a means for evaluating and selecting Long-Term Regional Transmission Facilities.[1099]

400. We are also unpersuaded by NESCOE's request that we defer to state preferences regarding benefits when the driver of the Long-Term Transmission Need is related to satisfying state laws, regulations, or policies. As noted above, the measurement and use of the required benefits in Long-Term Regional Transmission Planning is essential to ensuring just and reasonable Commission-jurisdictional rates such that the Commission cannot defer to states on this point. However, we note that Order No. 1920 requires consultation with the states regarding aspects of Long-Term Regional Transmission Planning, including a requirement that transmission providers consult with and seek the support of 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 and that provide transmission providers with the opportunity to select Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs, including those related to satisfying state laws, regulations, or policies.[1100] Further, as clarified in this order in the Stakeholder Process and Transparency section above, transmission providers must provide states with a meaningful opportunity to provide timely input on the development of Long-Term Scenarios, including factors and data inputs, and an opportunity to explain how their own policies and planning affect Long-Term Transmission Needs.[1101]

f. Individual Benefits

i. Final Rule Benefit 2(a): Reduced Loss of Load Probability; or Final Rule Benefit 2(b): Reduced Planning Reserve Margin

(a) Order No. 1920 Requirements

401. With respect to Final Rule Benefit 2, the Commission stated that this benefit can be characterized and measured as Final Rule Benefit 2(a), Reduced Loss of Load Probability, or as Final Rule Benefit 2(b), Reduced Planning Reserve Margin, two different methods for measuring the same underlying benefit. The Commission found that because there is an overlap between the 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 Final Rule Benefit 2(a) or 2(b).[1102]

(b) Requests for Rehearing and Clarification

402. SERTP Sponsors argue that the Commission should clarify that it does not intend to require transmission providers to establish a planning reserve margin other than the planning reserve margin established by the resource planners and load-serving entities on that transmission provider's system. SERTP Sponsors also assert that the Commission should clarify that any analysis under Final Rule Benefit 2 should not be used as a basis to challenge the planning reserve margin of a resource planner or load-serving entity established through state resource planning processes, and that the use of such an analysis is only intended for the purpose of evaluating potential Long-Term Regional Transmission Facilities that may under certain planning scenarios suggest a potential benefit.[1103]

(c) Commission Determination

403. We clarify that Order No. 1920 does not require transmission providers to establish a different planning reserve margin than the one established by resource planners or load-serving entities in a particular transmission provider's system, including in measuring Final Rule Benefit 2. We underscore here that any calculation of this benefit will only serve to support the benefits assessment of potential Long-Term Regional Transmission Facilities during the Long-Term Regional Transmission Planning process. While the Commission described examples of how transmission providers could measure certain benefits, the Commission did not require a specific measurement method for any of the required benefits.[1104] Further, the Commission noted that Final Rule Benefit 2 can be measured in one of two ways: (a) using reduced loss of load probability *or* (b) reduced planning reserve margin.[1105] In light of this clarification, we need not reach SERTP Sponsors' alternative argument that, absent this clarification, Order No. 1920 would raise concerns that the Commission has exceeded its jurisdiction.[1106]

404. In response to SERTP Sponsors' request to clarify that any analysis under Final Rule Benefit 2 should not be used as the basis for challenging a resource planner's or load-serving entity's planning reserve margin established through state resource planning processes, we clarify that any state resource planning process is a separate process subject to state jurisdiction and is beyond the scope of Order No. 1920.

ii. Final Rule Benefit 3: Production Cost Savings

(a) Order No. 1920 Requirements

405. In Order No. 1920, the Commission required transmission providers in each transmission planning region to measure and use Final Rule Benefit 3 in Long-Term Regional Transmission Planning. The Commission described this benefit 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

[1097] Order No. 1920, 187 FERC ¶ 61,068 at P 822.

[1098] Entergy Regional State Committee, *Resolution of the Entergy Regional State Committee,* at 3 (adopted June 30, 2023), *https://cdn.misoenergy.org/20230630%20-%20ERSC%20Resolution%20re%20MISO%20South%20Cost%20Allocation%20for%20Tranche%203629421.pdf* (''Each Tranche 3 project must individually satisfy the cost-benefit analysis used for the business case and cost allocation on a stand-alone basis.'')

[1099] Order No. 1920, 187 FERC ¶ 61,068 at P 966 (noting that transmission provider evaluation processes must result in determinations that ''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'').

[1100] *See id.* PP 914, 994.

[1101] Further, as discussed in the General Benefits Requirements Related to Cost Allocation section below, transmission providers can consider additional benefits for cost allocation purposes, including, but not limited to, those agreed to by Relevant State Entities and described elsewhere in Order No. 1920, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

[1102] Order No. 1920, 187 FERC ¶ 61,068 at P 755.

[1103] SERTP Sponsors Rehearing Request at 18.

[1104] Order No. 1920, 187 FERC ¶ 61,068 at P 727.

[1105] *Id.* P 748.

[1106] *See* SERTP Sponsors Rehearing Request at 18 n.46, 43 (Issue Statement 15) (citations omitted).

reduction in market prices as lower-cost suppliers set market clearing prices.[1107]

406. In Order No. 1920, the Commission disagreed with the assertion made in comments that production cost savings may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion. The Commission stated that 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. The Commission further stated that 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. The Commission observed that this reduced congestion allows 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.[1108]

(b) Requests for Rehearing and Clarification

407. SERTP Sponsors argue that the Commission should clarify that production cost analysis from state-approved integrated resource plans may be used to the extent feasible to satisfy the requirement to consider Final Rule Benefit 3. SERTP Sponsors further argue that, in the event of conflict, state-regulated integrated-resource-plan planning must control in accordance with FPA section 201.[1109]

408. Designated Retail Regulators assert that the Commission was mistaken in stating that a load-serving entity may benefit from reduced production costs associated with transmission construction even when its congestion costs are fully hedged. Designated Retail Regulators argue that as congestion is eliminated by transmission construction, the value of the load-serving entity's financial transmission rights decreases, and the load-serving entity incurs additional transmission charges associated with the new transmission facilities. Designated Retail Regulators assert that any benefit based on adjusted production cost must therefore consider congestion to determine if a load-serving entity receives any benefit or harm from transmission construction.[1110]

(c) Commission Determination

409. In response to SERTP Sponsors, we note that Order No. 1920 does not require a specific measurement method for any of the seven required benefits. We clarify that if transmission providers in a transmission planning region believe they can use production cost savings from one or more state integrated resource plans as an appropriate method to measure the value of Final Rule Benefit 3, they may propose to do so on compliance. As a general matter, we agree that states have authority over generation resource adequacy, which may include evaluation of production cost savings in state-regulated integrated resource plans. Order No. 1920, however, addresses transmission planning practices directly affecting Commission-jurisdictional rates, including by requiring that transmission providers consider the broader set of benefits (such as Final Rule Benefit 3) associated with Long-Term Regional Transmission Facilities. We therefore decline SERTP Sponsors' request to clarify that transmission providers must, in all circumstances, rely on such state evaluations of production cost savings in assessing the benefits associated with such facilities.[1111]

410. We decline Designated Retail Regulators' request for clarification regarding Final Rule Benefit 3 with respect to financial transmission rights. We continue to find that financial transmission rights allow the market participant that owns the right to mitigate the congestion charge along an existing path for the capacity of that path and note that 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. While the extent of production cost savings from any Long-Term Regional Transmission Facility or portfolio of such Facilities may vary among representative transmission providers, and transmission providers may propose on compliance to consider the effects of financial transmission rights on Final Rule Benefit 3, we decline to prospectively determine how any load-serving entity may or may not benefit from a reduction in regional production costs, including whether the degree to which a particular load-serving entity may have hedged against congestion would affect such benefits.

2. Measurement and Use of Other Benefits

a. Order No. 1920 Requirements

411. In Order No. 1920, the Commission declined 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), but permitted transmission providers to measure and use additional benefits beyond the set of seven required benefits (other benefits), 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.[1112] The Commission stated that, 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, which necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits that the Commission required transmission providers to include in their OATTs.[1113]

b. Requests for Rehearing and Clarification

412. PIOs assert that the Commission erred by not requiring transmission providers to measure and use the five additional benefits identified in the NOPR.[1114] PIOs assert that the Commission ignores its own evidence in the NOPR that the five additional

[1107] Order No. 1920, 187 FERC ¶ 61,068 at P 767.

[1108] *Id.* P 773 (citations omitted).

[1109] SERTP Sponsors Rehearing Request at 19.

[1110] Designated Retail Regulators Rehearing Request at 30–31.

[1111] In light of this clarification, we continue to conclude that Order No. 1920 is a lawful exercise of the Commission's statutory authority and does not intrude into areas of reserved state jurisdiction. *See supra* Statutory Authority section; SERTP Sponsors Rehearing Request at 18–19 nn.46 & 48, 43 (Issue Statement 15) (citations omitted). To the extent that transmission providers propose a different evaluation of production cost savings than reflected in state-regulated integrated resource plans, they will be doing so in the context of Order No. 1920's regulation of Commission-jurisdictional transmission planning processes.

[1112] Order No. 1920, 187 FERC ¶ 61,068 at PP 821–822.

[1113] *Id.* P 737.

[1114] PIOs Rehearing Request at 26–27.

proposed benefits have a proven track record, can be discretely measured, and are unlikely to cause duplication.[1115]

413. TAPS asserts that Order No. 1920's lack of a requirement for transmission providers to fully explain and justify additional benefits used to evaluate Long-Term Regional Transmission Facilities is an unjustified departure from the NOPR and inconsistent with the final rule's directive requiring transmission providers to describe how they will measure each of the seven required benefits on compliance. TAPS states that the final rule invites transmission providers to supplement Order No. 1920's required benefits, seemingly abandoning concerns about double-counting. TAPS further argues that the flexibility regarding additional benefits also provides an opportunity to selectively apply additional benefits on a transmission facility or plant-specific basis, inviting discrimination.[1116] TAPS also asserts that it is unclear whether the final rule's requirements for transmission providers to be ''open and transparent'' applies to the process of deciding whether to use and how to measure additional benefits or to the implementation of the additional benefits for specific projects. TAPS contends that it should apply to both.[1117]

c. Commission Determination

414. We are not persuaded by PIOs' rehearing request concerning the Commission's decision in Order No. 1920 to not require the measurement and use of benefits other than the seven required benefits, such as the five additional benefits identified by the Commission in the NOPR. The Commission determined that measurement and use of the set of seven required benefits constituted the just and reasonable replacement rate. Furthermore, the Commission explained its reasoning in Order No. 1920 for only requiring the measurement and use of seven required benefits and not other benefits, including recognizing commenters' concerns about duplication of certain benefits and the difficulty of measuring certain benefits.[1118] The Commission also explained that the list of seven required benefits only requires 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.[1119]

415. With respect to TAPS' concerns regarding a lack of a requirement for transmission providers to explain and justify other benefits on compliance, we believe that the approach in the final rule is reasonable because it provides transmission providers with greater flexibility to consider potential additional benefits of Long-Term Regional Transmission Facilities beyond the seven required benefits. We further find that, by providing transparency, the requirements of the final rule are sufficient to avoid undue discrimination. Specifically, Order No. 1920 requires transmission providers that measure and use any other benefits beyond the set of seven required benefits to 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.[1120] Moreover, the Commission stated that 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, which necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits that the Commission required transmission providers to include in their OATTs.[1121] Such transparency will limit the opportunities for transmission providers to measure and use in Long-Term Regional Transmission Planning any benefits in addition to the required benefits in an unduly discriminatory manner.

416. We therefore grant TAPS' request for clarification that the final rule's requirements for transmission providers to be ''open and transparent'' applies to the process of deciding whether to use and how to measure other benefits in addition to the required benefits as well as to the implementation of other benefits for specific Long-Term Regional Transmission Facilities, as discussed above.

3. Identification, Measurement, and Evaluation of Benefits

a. Order No. 1920 Requirements

417. In Order No. 1920, the Commission required transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the set of seven required benefits, sufficient only to enable stakeholders to understand the manner by which transmission providers will measure these benefits.[1122] Order No. 1920 provided flexibility to transmission planners to specify the method for measuring each of the seven required benefits,[1123] as well as discretion to measure and use additional benefits that go beyond the set of seven required benefits, 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.[1124]

b. Requests for Rehearing and Clarification

418. SERTP Sponsors request that the Commission clarify that it did not intend for transmission providers to engage in generation or resource planning as part of the Long-Term Regional Transmission Planning process, as doing so would violate FPA section 201 because it would intrude upon state-jurisdictional resource decisions. SERTP Sponsors also request clarification that it is reasonable for transmission providers to establish protocols by which they can rely, to the extent available, on resource planners and load-serving entities for data in support of generation-based benefits.[1125]

c. Commission Determination

419. In response to SERTP Sponsors' request, we clarify that Order No. 1920 does not require transmission providers to engage in generation or resource planning as part of Long-Term Regional Transmission Planning. The requirement for transmission providers to measure and use the set of seven required benefits in Long-Term Regional Transmission Planning is necessary for transmission providers to consider a sufficiently broad range of benefits when evaluating and determining whether to select a Long-Term Regional Transmission Facility as the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs and for purposes of conducting Long-Term Regional Transmission Planning, and not as a

[1115] *Id.* at 27 (citing NOPR, 179 FERC ¶ 61,028 at PP 208–209, 213–225).

[1116] TAPS Rehearing Request at 12–13.

[1117] *Id.* at 11.

[1118] Order No. 1920, 187 FERC ¶ 61,068 at P 724.

[1119] *Id.* P 724.

[1120] *Id.* PP 821–822.

[1121] *Id.* P 737.

[1122] *Id.* PP 837, 840.

[1123] *Id.* P 839.

[1124] *Id.* P 822.

[1125] SERTP Sponsors Rehearing Request at 17–18.

basis to cause transmission providers to engage in resource planning.[1126]

420. Further, as requested by SERTP Sponsors, we clarify that Order No. 1920 does not prohibit transmission providers from proposing to establish protocols by which they can rely, to the extent available, on resource planners and load-serving entities for generation-based data and information in satisfying the requirement to measure the benefits of Long-Term Regional Transmission Facilities. In Order No. 1920, the Commission provided flexibility to transmission providers to specify the method for measuring each of the seven required benefits and did not mandate any specific method for measuring those seven benefits. Order No. 1920 also provided the flexibility for transmission providers to establish protocols to obtain data, to the extent available, from resource planners and load-serving entities to measure the benefits of specific Long-Term Regional Transmission Facilities. However, we re-emphasize that, whether the transmission providers themselves measure the benefits of Long-Term Regional Transmission Facilities, or instead establish protocols by which they can rely on resource planners or load-serving entities for generation-based data and information to measure the benefits, the general description in the OATT of the method that the transmission provider uses to measure each of the required benefits must be sufficient to enable stakeholders to understand the manner by which transmission providers will measure those benefits, as noted in Order No. 1920.[1127]

4. Benefits Horizon

a. Order No. 1920 Requirements

421. In Order No. 1920, the Commission required 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 the Commission stated that this minimum 20-year benefit horizon must be used both for the evaluation and selection of Long-Term Regional Transmission Facilities.[1128] In addition, in Order No. 1920, the Commission stated 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.[1129]

422. In prohibiting transmission providers from discounting benefits to reflect uncertainty over the 20-year benefits horizon, the Commission stated that Order No. 1920 affords transmission providers with considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning through the process to develop Long-Term Scenarios.[1130] In addition, the Commission noted that 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.[1131] As a result, the Commission determined that transmission providers have considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning, including the calculation of benefits under different future scenarios, and that transmission providers did not need additional flexibility that would be realized by discounting benefits over time specifically due to future uncertainty.[1132]

b. Requests for Rehearing and Clarification

423. SERTP Sponsors request rehearing of the Commission's determination in Order No. 1920 to prohibit discounting of the measured benefits of Long-Term Regional Transmission Facilities based on uncertainty over the minimum 20-year benefit horizon. According to SERTP Sponsors, by requiring a 20-year benefits estimation without permitting discounting to reflect uncertainty, while also allowing a weighted-benefits approach to account for uncertainty, Order No. 1920's requirement and authorization are unclear and contradictory, and therefore arbitrary and capricious.[1133] Similarly, Dominion states that the Commission must provide transmission providers with the flexibility to discount the measured benefits to reflect uncertainty over the minimum 20-year horizon for purposes of selection and evaluation of projects.[1134]

c. Commission Determination

424. We sustain the finding in Order No. 1920 that, while transmission providers may discount the value of the benefits calculated for purposes of determining the present value of those benefits, they may not further reduce the estimates of those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits. We disagree with SERTP Sponsors that Order No. 1920 is contradictory in allowing the use of a weighted-benefits approach for evaluating Long-Term Regional Transmission Facilities while also prohibiting the reduction in estimates of measured benefits based on uncertainty over the minimum 20-year horizon. These two techniques are not the same, and allowing one but prohibiting the other is not contradictory. Permitting transmission providers to use a weighted-benefits approach for Long-Term Regional Transmission Facilities allows transmission providers to measure the estimated total benefits that a particular Long-Term Regional Transmission Facility may provide across a range of Long-Term Scenarios, each with a different probability of occurrence.[1135] This method can help account for uncertainty in the total benefits that a Long-Term Regional Transmission Facility may provide and help to balance an over-reliance on any particular Long-Term Scenario. While we understand that applying a probability to a Long-Term Scenario, and its resulting benefits, may reduce

[1126] In light of this clarification, we need not reach SERTP Sponsors' alternative argument that, absent this clarification, Order No. 1920 would raise concerns that the Commission has exceeded its jurisdiction. *See id.* at 19 n.48, 43 (Issue Statement 15) (citations omitted).

[1127] Order No. 1920, 187 FERC ¶ 61,068 at P 840.

[1128] *Id.* P 859.

[1129] *Id.* P 865.

[1130] *Id.* PP 861, 865.

[1131] *Id.* P 862.

[1132] *Id.* PP 862, 865.

[1133] SERTP Sponsors Rehearing Request at 19–20, 43 (Issue Statement 16) (citations omitted); *see also id.* at 43 (Issue Statement 15) (citations omitted) (asserting that failure to grant clarification of the issues in Section II.C.3 of SERTP Sponsors' argument would result in the Commission intruding on state-jurisdictional resource decisions).

[1134] Dominion Rehearing Request at 21–25.

[1135] Under a weighted-benefits approach, transmission providers that use three Long-Term Scenarios with expected likelihoods of, for example, 30%, 30%, and 40%, would attribute these expected likelihoods to the benefits that the transmission provider measures under each Long-Term Scenario. The total estimated benefits of the Long-Term Regional Transmission Facility would then be calculated by summing the probability-adjusted benefits across these three Long-Term Scenarios (*i.e.,* the sum of the measured benefits in the first Long-Term Scenario multiplied by its 30% probability, plus the second Long-Term Scenario's benefits multiplied by 30%, plus the third Long-Term Scenario's benefits multiplied by 40%).

the benefits measured for that particular Long-Term Scenario, when aggregated, the probability-weighted benefits measured across all Long-Term Scenarios results in a representative estimate of the total benefits of the Long-Term Regional Transmission Facility as a whole while also accounting for uncertainty regarding the likelihood of different Long-Term Scenarios being realized.

425. On the other hand, we continue to find that allowing transmission providers to reduce the estimates of certain benefits based only on the relative certainty over the 20-year benefits horizon is unnecessary given other flexibilities provided to transmission providers to manage uncertainty in planning over a minimum of 20 years, for the reasons discussed in Order No. 1920.[1136] For example, in addition to the use of a weighted-benefits approach, transmission providers have flexibility in how they account for the factors that go into Long-Term Scenario development once, as discussed elsewhere in this rule, transmission providers consult with Relevant State Entities and their authorized representatives as to how to account for factors related to state policy when determining the assumptions that will be used in the development of Long-Term Scenarios, as well as in determining *how* to account for such a state-related factor when developing Long-Term Scenarios when such state input is available.[1137]

426. As a result, we continue to believe that prohibiting the discounting of benefits based on relative certainty over the 20-year benefits horizon is reasonable and strikes an appropriate balance between preventing an excessive undercounting of benefits and allowing transmission providers to account for uncertainty in measuring benefits of Long-Term Regional Transmission Facilities across Long-Term Scenarios. For these reasons, we also disagree with Dominion that transmission providers must be afforded the flexibility to discount benefits based on the uncertainty in planning over a minimum 20-year horizon.

427. SERTP Sponsors do not explain how, in the absence of their requested clarification regarding discounting the benefits of Long-Term Regional Transmission Facilities, Order No. 1920 would ''intrude[ ] upon state-jurisdictional resource decisions.'' [1138] Regardless, we would be unpersuaded by this argument on its merits because, as described above, Order No. 1920 falls comfortably within the Commission's jurisdiction to regulate practices directly affecting Commission-jurisdictional rates.[1139] The manner in which benefits of Long-Term Regional Transmission Facilities are assessed is such a Commission-jurisdictional practice.

5. Evaluation of the Benefits of Portfolios of Transmission Facilities

a. Order No. 1920 Requirements

428. In Order No. 1920, the Commission allowed, but not did 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, the Commission required 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.[1140]

b. Requests for Rehearing and Clarification

429. PIOs request rehearing of the Commission's decision in Order No. 1920 to not require transmission providers to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1141] PIOs state that the record in this docket includes widespread commenter support and substantial evidence, ranging from expert reports to examples of existing processes, demonstrating the benefits of using a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1142] PIOs argue that by allowing transmission providers to continue to evaluate the benefits of Long-Term Regional Transmission Facilities on a facility-by-facility basis, the Commission undermines Order No. 1920's central purpose of requiring planning for system-wide transmission needs on a comprehensive and regional basis and leaves in place unjust and unreasonable rates.[1143] PIOs state that the Commission could provide transmission providers with flexibility while meeting the goals of Order No. 1920 by establishing a rebuttable presumption that Long-Term Regional Transmission Facilities be assessed on a portfolio basis, which transmission providers could overcome by demonstrating that the portfolio approach is inapplicable in a particular instance.[1144]

430. Undersigned States [1145] and Designated Retail Regulators request rehearing of Order No. 1920's decision to allow transmission providers to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities.[1146] Designated Retail Regulators and Undersigned States opine that the Commission should prohibit transmission providers from using the portfolio approach because, by allowing the bundling of economic and uneconomic facilities such that all facilities in a portfolio appear economic on a collective basis, the portfolio approach spreads uneconomic project costs to non-beneficiaries.[1147] Designated Retail Regulators and Undersigned States further argue that the portfolio approach results in the unjust and unreasonable recovery of costs exceeding benefits and that every facility approved for construction should be economic and meet the required benefits-to-cost ratio on a stand-alone basis.[1148]

c. Commission Determination

431. We are unpersuaded by PIOs', Undersigned States', and Designated Retail Regulators' requests for rehearing of the Commission's decision 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. We disagree with PIOs' arguments that the Commission's decision not to require transmission providers to use a portfolio approach undermines the goals or purpose of Order No. 1920 or leaves unjust and unreasonable rates in

[1136] Order No. 1920, 187 FERC ¶ 61,068 at P 865.

[1137] *See supra* Long-Term Scenarios Requirements, Stakeholder Process and Transparency section.

[1138] SERTP Sponsors Rehearing Request at 43 (Issue Statement 15) (citations omitted); *id.* at 37–41 (generic argument that failure to grant certain clarifications intrudes on state jurisdiction or may implicate the major questions doctrine, without discussion of discounting benefits).

[1139] *See supra* Statutory Authority section.

[1140] Order No. 1920, 187 FERC ¶ 61,068 at P 889.

[1141] PIOs Rehearing Request at 47 (citations omitted).

[1142] *Id.* at 44–46.

[1143] *Id.* at 47.

[1144] *Id.* 47–48 (citing US DOE NOPR Initial Comments at 34–35).

[1145] Undersigned States note that the state of North Dakota does not join in the portion of Undersigned States' request for rehearing that addresses the final rule's determinations concerning the portfolio approach. Undersigned States Rehearing Request at 29 n.19.

[1146] Designated Retail Regulators Rehearing Request at 33–34; Undersigned States Rehearing Request at 29–30.

[1147] Designated Retail Regulators Rehearing Request at 34; Undersigned States Rehearing Request at 30.

[1148] Designated Retail Regulators Rehearing Request at 34; Undersigned States Rehearing Request at 30.

place.[1149] We continue to find that the advantages of a portfolio approach to evaluating benefits must be balanced against other considerations and that it is appropriate to provide transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach, subject to the requirement that transmission providers that propose to use a portfolio approach include provisions in their OATTs regarding their use of the portfolio approach.[1150]

432. Specifically, we find that the advantages of a portfolio approach to evaluating benefits—including administrative efficiencies related to economies of scale and a more stable or even distribution of benefits, which is likely to facilitate agreement on regional cost allocation—must be weighed against the fact that a portfolio approach may not be appropriate in all instances. For example, a facility-by-facility approach may be more appropriate if Long-Term Scenarios reveal the same or nearly identical constraints in discrete and isolated areas of the transmission system where system upgrades would be beneficial. We find that transmission providers are in the best position to determine in any given circumstance whether a portfolio or facility-by-facility approach to evaluate the benefits of Long-Term Regional Transmission Facilities is more appropriate. Therefore, we sustain the determination in Order No. 1920 to provide transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach, subject to the requirement that transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities include provisions in their OATTs regarding their use of the portfolio approach.

433. We are also unpersuaded by Designated Retail Regulators' and Undersigned States' requests that the Commission prohibit transmission providers from using a portfolio approach to evaluate the benefits of Long-Term Regional Transmission Facilities. We note that the Commission has previously accepted the use of the portfolio approach to the evaluation of transmission facilities.[1151] In response to Undersigned States' claim that the portfolio approach allocates uneconomic project costs to non-beneficiaries, we note that the measurement and use of the benefits of Long-Term Regional Transmission Facilities, whether on a portfolio or facility-by-facility basis, is a requirement for the evaluation of Long-Term Regional Transmission Facilities for the purposes of potential selection. Order No. 1920 provides transmission providers with flexibility as to the consideration of benefits in their cost allocation methods for Long-Term Regional Transmission Facilities, subject to the requirement that transmission providers demonstrate that such cost allocation methods allocate costs in a manner that is at least roughly commensurate with estimated benefits.[1152] Thus, Designated Retail Regulators' and Undersigned States' arguments that the portfolio approach to evaluation of benefits will result in the allocation of costs for uneconomic facilities are unfounded.

D. Evaluation and Selection of Long-Term Regional Transmission Facilities

1. Minimum Requirements

a. Order No. 1920 Requirements

434. In Order No. 1920, the Commission required 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.[1153] The Commission further held that the transmission developer of a selected Long-Term Regional Transmission Facility will be eligible to use the applicable cost allocation method for that Long-Term Regional Transmission Facility.

435. The Commission provided flexibility to transmission providers to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria,[1154] provided that they (1) are transparent and not unduly discriminatory; [1155] (2) aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs; [1156] and (3) seek to maximize benefits accounting for costs over time without over-building transmission facilities.[1157]

436. As to the requirement that transmission providers' evaluation processes, including selection criteria, are transparent and not unduly discriminatory, the Commission explained that transmission providers' evaluation of Long-Term Regional 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 Long-Term Regional Transmission Facilities) was selected or not selected.[1158] The Commission also explained that this determination must include the estimated costs and measured benefits of each Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) that transmission providers evaluated in the Long-Term Regional Transmission Planning process, regardless of whether the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.[1159] The Commission further explained that, where transmission providers employ a portfolio approach to evaluating and selecting Long-Term Regional Transmission Facilities, transmission providers may provide the measured benefits included in this determination on an aggregate basis.[1160]

437. As to the requirement that transmission providers' evaluation processes, including selection criteria, must aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs, the Commission explained that evaluation processes must: (1) identify one or more Long-Term Regional Transmission Facilities (or portfolio of Long-Term Regional Transmission Facilities) that address the Long-Term Transmission Needs that transmission providers identify in Long-Term Regional Transmission Planning; (2)

[1149] *See* PIOs Rehearing Request at 47.

[1150] Order No. 1920, 187 FERC ¶ 61,068 at PP 889–890. Order No. 1920 requires transmission providers that propose to use a portfolio approach to indicate in their proposed OATTs that they will use a portfolio approach. However, Order No. 1920 does not require transmission providers to indicate whether they will use a portfolio approach for all Long-Term Regional Transmission Facilities or only in certain specified instances, nor to describe how they will analyze the benefits of Long-Term Regional Transmission Facilities under a portfolio approach, as such requirements could impede transmission provider consideration and development of portfolio approaches. *Id.* P 889.

[1151] *Midwest Indep. Transmission Sys. Operator, Inc.,* 133 FERC ¶ 61,221, at PP 221–222 (2010), *order on reh'g and compliance filing,* 137 FERC ¶ 61,074 (2011), *aff'd in part, dismissed in part and remanded in part sub nom. Ill. Com. Comm'n* v. *FERC,* 721 F.3d 764, 780 (7th Cir. 2013).

[1152] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1478, 1506 (citing *ICC* v. *FERC I,* 576 F.3d at 477; *ICC* v. *FERC III,* 756 F.3d at 564).

[1153] Order No. 1920, 187 FERC ¶ 61,068 at P 911.

[1154] *Id.* P 924.

[1155] *Id.* P 954.

[1156] *Id.* P 955.

[1157] *Id.* P 964.

[1158] *Id.* P 954.

[1159] *Id.* PP 954, 966.

[1160] *Id.* P 966 n.2121.

estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities that are identified or proposed for potential selection; (3) designate a point in the evaluation process that is no later than three years following the beginning of the Long-Term Regional Transmission Planning cycle at which transmission providers will determine to select or not to select identified or proposed Long-Term Regional Transmission Facilities; and (4) culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of Long-Term Regional Transmission Facilities) was selected or not selected.[1161] The Commission also provided 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/or using some other method. Consistent with cost allocation principle (3), however, the Commission prohibited transmission providers from imposing as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[1162]

438. Finally, as to the requirement that transmission providers' evaluation processes, including selection criteria, must seek to maximize benefits accounting for costs over time without over-building transmission facilities, the Commission stated that transmission providers could adopt evaluation processes and selection criteria that would allow transmission providers to make selection decisions while addressing the uncertainty inherent in Long-Term Regional Transmission Planning. For example, transmission providers could include features that minimize 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, such as by using a least-regrets or weighted-benefits approaches.[1163] The Commission explained that, consistent with this requirement, transmission providers may not disregard benefits that they are required to use and measure, and may not do so even where those benefits only are measured under certain transmission system conditions.[1164] The Commission further explained that transmission providers may not adopt an approach under which a Long-Term Regional Transmission Facility would be required to meet the selection criteria in every Long-Term Scenario and sensitivity.[1165]

b. Requests for Rehearing and Clarification

439. NRECA argues that the Commission violated the APA's notice-and-comment requirements because the NOPR did not propose the ''prescriptive'' requirements set forth in Order No. 1920 related to the evaluation of Long-Term Regional Transmission Facilities.[1166] These include the requirement that transmission providers identify Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs, estimate the costs and measure the benefits of such facilities, and designate a point in the evaluation process, no later than three years from the date when the Long-Term Regional Transmission Planning cycle begins, at which time the transmission provider will determine whether to select or not select those identified Long-Term Regional Transmission Facilities.[1167]

440. NRECA also requests that the Commission grant rehearing and require that transmission providers' selection criteria ensure the selection of Long-Term Regional Transmission Facilities that meet the reasonable needs of load-serving entities, which NRECA argues that they must do under FPA section 217(b)(4). Further, NRECA contends that FPA section 217(b)(4) requires that selection criteria enable 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.[1168]

441. PIOs request rehearing of the Commission's determination to allow transmission providers to adopt benefit-cost ratios as high as 1.25-to-1.00 and request that the Commission require benefit-cost ratios no higher than 1.00-to-1.00. PIOs contend that a 1.25-to-1.00 benefit-cost ratio does not work in the context of scenario-based planning using a portfolio approach because some Long-Term Regional Transmission Facilities may, in isolation, be below 1.25-to-1.00 despite raising the value of a portfolio of Long-Term Regional Transmission Facilities above such a threshold.[1169] PIOs also argue that the measured benefits of certain Long-Term Regional Transmission Facilities may depend on the Long-Term Scenario or sensitivity within which benefits are measured, and that it does not make sense to apply a benefit-cost ratio threshold to Long-Term Regional Transmission Facilities whose benefits are not fixed.[1170]

442. ITC requests rehearing of the Commission's decision to allow, but not to require, transmission providers to adopt least-regrets approaches to selecting Long-Term Regional Transmission Facilities. ITC argues that, given other requirements in Order No. 1920, a least-regrets approach would hedge against the inherent uncertainty of Long-Term Regional Transmission Planning by ensuring that selected Long-Term Regional Transmission Facilities provide robust benefits over a wide variety of future system conditions.[1171]

443. Dominion states that Order No. 1920 is clear that transmission providers ''*can* compare calculated benefits [of Long-Term Regional Transmission Facilities] to costs for purposes of project evaluation and selection.'' [1172]

[1161] *Id.* P 955. As to the identification of Long-Term Regional Transmission Facilities, Order No. 1920 requires, consistent with Order Nos. 890 and 1000, that nonincumbent transmission developers be able to propose transmission facilities in Long-Term Regional Transmission Planning, and that therefore transmission providers 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. *Id.*

[1162] *Id.* P 958 (citation omitted).

[1163] *Id.* P 967. The Commission explained that, under a least-regrets approach, transmission providers would select Long-Term Regional Transmission Facilities if those facilities are net beneficial in more than one Long-Term Scenario and sensitivity analysis 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. Under a weighted-benefits approach, transmission providers 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. *Id.*

[1164] *Id.* P 965.

[1165] *Id.* P 968.

[1166] NRECA Rehearing Request at 14.

[1167] NRECA Rehearing Request at 14–15 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 381, 955).

[1168] *See* NRECA Rehearing Request at 39–43. As with its arguments related to the discretion provided under Order No. 1920 for transmission providers to determine that factors in Factor Category Three may not affect Long-Term Transmission Needs, NRECA also argues with respect to selection criteria that the Commission should revisit its conclusion that *South Carolina Public Service Authority* v. *FERC* remains good law on the meaning of FPA section 217(b)(4). *Id.* at 40–41.

[1169] PIOs Rehearing Request at 48–49 (citing PIOs NOPR Initial Comments, ex. A at 12–17).

[1170] *Id.* at 48–49.

[1171] ITC Rehearing Request at 11–12.

[1172] Dominion Rehearing Request at 25 (emphasis added) (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 955, 964–965).

Dominion requests that the Commission clarify that transmission providers may weigh measured benefits against ''other factors'' and that transmission providers may propose ''what factors will be considered,'' provided that transmission providers' selection criteria are ''sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected.'' [1173] Dominion further requests that the Commission clarify what different ''costs'' transmission providers can consider and weigh against measured benefits beyond the direct costs of the construction and operation of the specific Long-Term Regional Transmission Facility. By way of example, Dominion explains that some Long-Term Regional Transmission Facilities may allow for the delivery of more generation to an area of high load demand, while also creating reliability issues on another transmission facility. If upgrades to that transmission facility are made in response to those reliability issues, Dominion requests clarification that transmission providers can consider the costs of those upgrades to be a ''cost'' of the Long-Term Regional Transmission Facility.[1174]

444. Finally, TAPS requests rehearing of the Commission's decision not to require that transmission providers calculate and provide to the transmission planning region's stakeholders TAPS's proposed ''affordability metrics.'' TAPS explains that this proposed requirement would include the projected incremental transmission rate impact that each Long-Term Regional Transmission Facility would provide, if selected, and the projected total transmission rate that transmission customers would pay if all selected Long-Term Regional Transmission Facilities are placed in service. TAPS explains that transmission providers should make these calculations on the basis of the default *ex ante* Long-Term Regional Transmission Cost Allocation Method (in the absence of any state agreement), covering a period extending at least 20 years after the Long-Term Regional Transmission Facility is expected to be in commercial operation, and would be required to share their assumptions and calculations. TAPS explains that transmission providers should also provide a process for stakeholders to submit questions and verify information. TAPS argues that the Commission's rejection of affordability metrics was ''conclusory'' and did not satisfy the Commission's obligation to engage with comments.[1175]

c. Commission Determination

445. We disagree with the rehearing arguments submitted by NRECA. First, the Commission did not violate the APA's notice-and-comment requirements when it modified the NOPR proposal to be more ''prescriptive'' [1176] by requiring that the evaluation and selection processes that transmission providers propose must: (1) identify Long-Term Regional Transmission Facilities that address the Long-Term Transmission Needs they have identified; (2) estimate the costs and measure the benefits of such facilities; and (3) designate a point in the evaluation process when the transmission provider will determine whether to select or not select those facilities. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a ''logical outgrowth'' of the proposed rule.[1177]

446. The final rule is a logical outgrowth of the NOPR in this regard. The Commission described Long-Term Regional Transmission Planning in the NOPR as regional transmission planning that: (1) identifies transmission needs driven by changes in the resource mix and demand; (2) evaluates transmission facilities that meet such needs; and (3) identifies and evaluates such transmission facilities for potential selection to meet those needs.[1178] The NOPR also proposed to require that transmission providers' selection criteria ''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.'' [1179] In Order No. 1920, the Commission modified 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.'' [1180] The Commission then set forth procedural requirements that require transmission providers to meet the NOPR definition of Long-Term Regional Transmission Planning by: (1) identifying Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs; (2) estimating the costs and measuring the benefits of such facilities as part of the evaluation process; and (3) designating a point when transmission providers will make a decision to select or not select such facilities.[1181] These additional procedural clarifications satisfy the logical outgrowth test because the requirements in Order No. 1920 achieve the same ends using very similar means to those proposed in the NOPR. Accordingly, we find that the evaluation requirements follow logically from the NOPR and that the NOPR adequately framed the subjects for discussion such that a reasonable member of the regulated class would anticipate the general aspects of the final rule.[1182]

447. Second, we disagree with NRECA's rehearing argument that, in order to satisfy FPA section 217(b)(4), the Commission must impose a specific requirement that transmission providers' selection criteria ensure the selection of Long-Term Regional Transmission Facilities that meet the reasonable needs of load-serving entities and enable 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. Fulfilling the requirements of FPA section 217(b)(4) does not require that the Commission impose the selection criterion that NRECA prefers, and we find that the criteria that the Commission required represent a superior and, in any case, just and reasonable and not unduly discriminatory or preferential approach to this issue. Moreover, the Commission explained in Order No. 1920 that, ''[t]hrough the requirements of this final rule, we seek to ensure that adequate

[1173] *Id.* at 25–26 (punctuation omitted) (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 737).

[1174] *Id.*

[1175] TAPS Rehearing Request at 20–22 (''[T]he 'Commission cannot satisfy its mandate to engage with parties' comments by relying on conclusory statements that dismissed a party's concerns without providing reasoned analysis.''' (internal quotation and alteration omitted) (quoting *Cal. Pub. Utils. Comm'n* v. *FERC,* 20 F.4th 795, 804 (D.C. Cir. 2021)).

[1176] NRECA Rehearing Request at 14.

[1177] *Long Island Care at Home, Ltd.* v. *Coke,* 551 U.S. 158, 174–75 (2007) (*Long Island Care*). *See also Am. Paper Inst.* v. *EPA,* 660 F.2d 954, 959 n.13 (4th Cir. 1981) (''An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.'') (emphasis added).

[1178] *See* NOPR, 179 FERC ¶ 61,028 at P 68. Order No. 1920 adopted a definition of Long-Term Transmission Needs that includes transmission needs driven by changes in the resource mix and demand. *See* Order No. 1920, 187 FERC ¶ 61,068 at P 299 (describing the drivers of Long-Term Transmission Needs as including changes in the resource mix and changes in demand).

[1179] NOPR, 179 FERC ¶ 61,028 at P 245.

[1180] Order No. 1920, 187 FERC ¶ 61,068 at P 955.

[1181] *Id.*

[1182] *Conn. Light & Power Co.* v. *Nuclear Regul. Comm'n,* 673 F.2d 525, 533 (D.C. Cir. 1982); *Telesat Canada* v. *FCC,* 999 F.3d 707, 713–14 (D.C. Cir. 2021).

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).'' [1183]

448. We further disagree with the rehearing arguments submitted by PIOs, and we sustain the Commission's holding that, consistent with Order No. 1000 regional cost allocation principle (3), transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.[1184] We do not agree with PIOs that this holding is inconsistent with the use of a portfolio approach to selecting Long-Term Regional Transmission Facilities. While PIOs are correct that the benefits of Long-Term Regional Transmission Facilities may depend on the Long-Term Scenario or sensitivity in which they are measured, Order No. 1920 does not require transmission providers to apply benefit-cost ratios within specific Long-Term Scenarios or sensitivities.[1185] Further, the fact that the measured benefits of Long-Term Regional Transmission Facilities may differ among the Long-Term Scenarios or sensitivities studied does not render the use of benefit-cost ratios incompatible with Long-Term Regional Transmission Planning. In fact, the least-regrets and weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities described in Order No. 1920 are examples of how transmission providers may make selection decisions notwithstanding the fact that the measured benefits of Long-Term Regional Transmission Facilities may differ depending on the Long-Term Scenario or sensitivity in which they are measured.[1186]

449. We also disagree with the rehearing arguments advanced by ITC. While we agree with ITC that a least-regrets approach to selecting Long-Term Regional Transmission Facilities may allow transmission providers to address the inherent uncertainty of Long-Term Regional Transmission Planning, we disagree that this is the only such approach,[1187] and therefore we sustain the Commission's holding that transmission providers are not required to use this approach.[1188] Generally, the Commission attempted in Order No. 1920 to ensure that transmission providers have the flexibility that they need to develop evaluation processes, including selection criteria, that meet the minimum requirements set forth in Order No. 1920, and we are not persuaded by PIOs or ITC to limit that flexibility here, either by reducing the maximum benefit-cost ratio that transmission providers may propose to use as a selection criterion in Long-Term Regional Transmission Planning or by requiring a particular selection approach.

450. We grant clarification, in part, to Dominion. As an initial matter, we clarify that transmission providers' evaluation processes must—not can—compare the measured benefits of Long-Term Regional Transmission Facilities against their estimated costs.[1189] The purpose of such a comparison is for transmission providers to determine the benefits of Long-Term Regional Transmission Facilities for purposes of applying the transmission provider's selection criteria.[1190] We further clarify that, once a transmission provider makes a selection decision, *i.e.,* for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities), and, if a State Agreement Process is used, once a cost allocation method is agreed upon, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how those estimated costs will be allocated, by zone (*i.e.,* by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of those estimated benefits as imputed to each zone, as such benefits can be reasonably estimated. The increase in transparency from this posting requirement ensures that transmission providers make available information that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected. As to Dominion's request that the Commission clarify what—aside from project costs—transmission providers may compare to measured benefits, we reiterate here that transmission providers may propose qualitative measures in their evaluation processes or qualitative selection criteria,[1191] provided that they meet the minimum requirements set forth in Order No. 1920 with which transmission providers' evaluation processes, including selection criteria, must comply.[1192] We further clarify that, contrary to Dominion's understanding,[1193] transmission providers' evaluation processes must culminate in a *determination*—not selection criteria—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.[1194] Finally, we clarify that the Commission generally provides transmission providers with the discretion to use engineering judgment in designing and conducting transmission planning studies, and we therefore decline to address Dominion's hypothetical in the abstract.

451. Finally, we are not persuaded by the arguments raised on rehearing by TAPS regarding its proposed ''affordability metrics.'' We find that the potential benefits of requiring that transmission providers make these metrics available are outweighed by the potential burden on transmission providers, who would need to determine on a customer-by-customer basis the effect on incremental rates of

[1183] Order No. 1920, 187 FERC ¶ 61,068 at P 1001. *See also id.* PP 283, 447 (discussing Commission's obligations under FPA section 217(b)(4) and its application to Order No. 1920). We also reject NRECA's argument that the Commission should revisit its conclusion that *South Carolina Public Service Authority* v. *FERC* remains good law for the same reasons provided in the Other Specific Required Categories of Factors section above.

[1184] *Id.* P 958.

[1185] *See id.* P 956 (requiring transmission providers to 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).

[1186] *Id.* P 967. *See infra* Benefits Horizon section.

[1187] *See id.* P 967 (describing least-regrets *and* weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities as potential methods to manage uncertainty).

[1188] *Id.* P 968.

[1189] *See id.* P 955 (''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.'' (emphasis added)); *id.* P 964 (requiring transmission providers to propose evaluation processes, including selection criteria, that seek to *maximize benefits accounting for costs* over time without over-building transmission facilities) (emphasis added).

[1190] *See id.* P 956 (holding that transmission providers must make clear the methods they used to analyze the benefits of Long-Term Regional Transmission Facilities for purposes of selection).

[1191] *Id.* P 961.

[1192] *See id.* PP 954–971.

[1193] *See* Dominion Rehearing Request at 26 (''Dominion Energy understands that the Final Rule gives Transmission Providers an opportunity to propose what factors will be considered so long as the *selection criteria* is 'sufficiently detailed to understand why a particular Long-Term Regional Transmission Facility . . . was selected or not selected.'') (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 737) (emphasis added).

[1194] Order No. 1920, 187 FERC ¶ 61,068 at PP 737, 954–955, 966, 1214.

a wide variety of rate design and cost recovery factors in order to produce a meaningful analysis. Therefore, we decline to adopt any requirement to calculate and make available the ''affordability metrics'' as described by TAPS. However, even though we do not require transmission providers to calculate rate impacts, as discussed above, we do require transparency regarding the allocation of costs after Long-Term Transmission Facilities are selected.

2. Role of Relevant State Entities

a. Order No. 1920 Requirements

452. In Order No. 1920, the Commission required 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.[1195] The Commission declined to adopt the NOPR proposal to require that transmission providers include in their OATTs a process to coordinate with the transmission planning region's Relevant State Entities in developing selection criteria.[1196] Instead, the Commission required transmission providers to demonstrate on compliance that they made good faith efforts to consult with and seek support from Relevant State Entities in their transmission planning region's footprint when developing the evaluation processes and selection criteria that they propose to include in their OATTs.[1197] The Commission did not require transmission providers to obtain the support of Relevant State Entities before proposing evaluation processes and selection criteria on compliance.[1198]

b. Requests for Rehearing and Clarification

453. Several parties request rehearing or clarification of Order No. 1920's requirements related to the role that Relevant State Entities will play in developing the evaluation processes, including selection criteria, that transmission providers will propose.[1199]

454. Designated Retail Regulators claim that the Commission violated the APA's notice-and-comment requirements because the NOPR required that states approve the selection criteria that transmission providers will propose to use in Long-Term Regional Transmission Planning, whereas the Commission did not require transmission providers to obtain their support in Order No. 1920. As such, Designated Retail Regulators conclude that Order No. 1920 is not a logical outgrowth of the NOPR proposal because it is ''surprisingly distant'' from the NOPR.[1200] Similarly, NRECA argues that Order No. 1920 is not a logical outgrowth of the NOPR because the Commission declined to adopt the NOPR proposal that transmission providers include a formal tariff process for coordinating with Relevant State Entities regarding transmission providers' selection criteria.[1201]

455. Arizona Commission argues that the Commission erred in not requiring transmission providers to obtain the agreement of the State of Arizona as to the evaluation processes, including selection criteria, that transmission providers will propose, and requests rehearing because the Commission did not offer any legitimate legal reason or sufficient justification for not requiring such state approval. Arizona Commission asserts that states alone have the inherent police power to regulate the utilities within their states and that the final rule improperly eliminates the State of Arizona's role with respect to selection criteria.[1202] NARUC requests that the Commission grant rehearing such that transmission providers would be required to include in their compliance filings any selection criteria that are ''promulgated and supported'' by Relevant State Entities.[1203]

456. Finally, NESCOE requests that the Commission clarify Order No. 1920 to provide guidance as to what constitutes ''good faith efforts'' on the part of transmission providers as they consult with and seek support from Relevant State Entities. NESCOE requests further clarification that the requirement that transmission providers ''consult with'' Relevant State Entities means that there is an ''unambiguous pathway'' for states' feedback to be heard and taken into account. Further, NESCOE observes that ''consult with'' can mean a range of things, from an offer of a one-hour meeting to preview potential selection criteria to interactive and substantive discussions, and it requests that the Commission confirm that the obligation to consult with Relevant State Entities means something more consequential than the former.[1204]

c. Commission Determination

457. We disagree with the arguments raised on rehearing by Designated Retail Regulators and NRECA that Order No. 1920 is not a logical outgrowth of the NOPR proposal. In particular, we disagree with Designated Retail Regulators that the NOPR proposed to require that states approve transmission providers' selection criteria.[1205] Instead, the NOPR proposed to require that transmission providers ''coordinate'' with Relevant State Entities in developing selection criteria, and the Commission explained that this would mean that transmission providers ''must consult with and seek support from'' Relevant State Entities.[1206] Neither statement can be construed as imposing a requirement that states approve the selection criteria to be proposed by transmission providers on compliance. In any event, the Commission adopted the exact proposal from the NOPR, namely, that transmission providers must consult with and seek support from Relevant State Entities, which was subject to a notice and comment period, as required under the APA.

458. Further, while NRECA is correct that in Order No. 1920, the Commission declined to adopt the NOPR proposal for transmission providers to propose on compliance OATT provisions providing for a ''process'' to coordinate with Relevant State Entities in developing selection criteria,[1207] this does not mean that Order No. 1920 is not a logical outgrowth of the NOPR proposal in this regard. As the D.C. Circuit has explained, ''[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step.'' [1208] The same is true here. Further, the Commission required that transmission providers

[1195] *Id.* P 994.

[1196] *Id.* P 995.

[1197] *Id.* P 994.

[1198] *Id.* P 996.

[1199] Arizona Commission Rehearing Request at 16; Designated Retail Regulators Rehearing Request at 48–50; NARUC Rehearing Request at 17–21; NESCOE Rehearing Request at 12; NRECA Rehearing Request at 6, 17–19.

[1200] Designated Retail Regulators Rehearing Request at 48–50 (quoting *Int'l Union, United Mine Workers of Am.* v. *Mine Safety & Health Admin.,* 407 F.3d 1250, 1260 (D.C. Cir. 2005)).

[1201] NRECA Rehearing Request at 6, 17–19.

[1202] *See* Arizona Commission Rehearing Request at 16.

[1203] NARUC Rehearing Request at 17.

[1204] NESCOE Rehearing Request at 12.

[1205] Designated Retail Regulators Rehearing Request at 48–49.

[1206] *See* NOPR, 179 FERC ¶ 61,028 at PP 241, 244.

[1207] NRECA Rehearing Request at 17–18.

[1208] *N.Y.* v. *EPA,* 413 F.3d 3, 44 (D.C. Cir. 2005) (per curiam) (quoting *Am. Iron & Steel Inst.* v. *EPA,* 886 F.2d 390, 400 (D.C. Cir. 1989)). *See also Long Island Care,* 551 U.S. at 175 (stating, in the context of rejecting claims that an agency provided legally defective notice because it did not finalize a proposed rule, ''[w]e do not understand why such a possibility was not reasonably foreseeable''); *Vanda Pharms., Inc.* v. *Ctrs. for Medicare & Medicaid Servs.,* 98 F.4th 483, 498 (4th Cir. 2024) (*Vanda Pharms*) (The APA's ''notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content'').

demonstrate good faith efforts as they consult with and seek support from Relevant State Entities.[1209] We continue to believe that these requirements are sufficient to ensure that transmission providers benefit from Relevant State Entities' views. Nevertheless, we note that Order No. 1920 does not prohibit transmission providers from adopting additional approaches for coordinating with Relevant State Entities regarding selection criteria and/or consulting with Relevant State Entities in the selection of particular Long-Term Regional Transmission Facilities, and we encourage transmission providers to do so.[1210]

459. We also disagree with the rehearing arguments of Arizona Commission and NARUC. Arizona Commission incorrectly claims that the Commission did not offer any ''legitimate legal or sufficient justification'' for not requiring state approval of evaluation processes.[1211] As the Commission explained, it is transmission providers who must propose on compliance an evaluation process and selection criteria that comply with the requirements of Order No. 1920, because Long-Term Regional Transmission Planning is the tariff obligation of each transmission provider.[1212] As the Commission further explained, achieving consensus may not be possible in every instance, and transmission providers nevertheless must submit compliance filings consistent with Order No. 1920 and the compliance timelines set forth therein.[1213] We deny NARUC's request to require transmission providers to include in their compliance filings any selection criteria that are ''promulgated and supported'' by Relevant State Entities. That said, we continue to 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.[1214] As such, we strongly encourage transmission providers to consider any selection criteria supported by Relevant State Entities.

460. Finally, we grant in part NESCOE's requests for clarification. We believe that ''good faith efforts'' is a reasonably well-understood standard that parties use in their contractual dealings with one another.[1215] We further believe that the good faith efforts standard is similar to a ''reasonable efforts'' standard, which can be defined as ''one or more actions rationally calculated to achieve a usually stated objective, but not necessarily with the expectation that all possibilities are to be exhausted.'' [1216] We expect that transmission providers can determine how to apply the ''good faith efforts'' standard as they consult with and seek support from Relevant State Entities as to the evaluation processes and selection criteria they will use in Long-Term Regional Transmission Planning. Therefore, we find that Order No. 1920 requires transmission providers to provide opportunities for Relevant State Entities to provide input on those proposed processes and to consider that feedback.[1217] We otherwise deny clarification and decline to address NESCOE's hypothetical interpretation of the standard.

3. Voluntary Funding

a. Order No. 1920 Requirements

461. In Order No. 1920, the Commission required 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 transmission providers' selection criteria.[1218]

462. The Commission provided transmission providers with flexibility to propose certain features of such a voluntary funding process in their compliance filings, provided that: (1) the process is transparent and not unduly discriminatory or preferential; and (2) they consult with and seek support from Relevant State Entities when developing such processes.[1219]

463. The Commission further required that transmission providers' proposed OATT provisions must describe: (1) the process by which transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that they receive timely notice and a meaningful opportunity; (2) the period during which Relevant State Entities and interconnection customers may exercise the voluntary funding option; (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.[1220] Finally, the Commission explained that, for any portion of the costs of a selected Long-Term Regional Transmission Facility that is not voluntarily funded, such remaining costs must be allocated according to either the applicable Long-Term Regional Transmission Cost Allocation Method or a cost allocation method resulting from a State Agreement Process.[1221]

b. Requests for Rehearing and Clarification

464. SERTP Sponsors request that the Commission clarify that the requirement in Order No. 1920 that transmission providers include in their OATTs a process to provide Relevant State Entities and interconnection customers with voluntary funding opportunities does not imply that the Commission

[1209] Order No. 1920, 187 FERC ¶ 61,068 at P 994.

[1210] *Id.* PP 994, 996. We reiterate, however, 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. *Id.* P 962. Doing so would deny transmission providers the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs, and therefore may lead to failing to address the deficiencies in the Commission's existing regional transmission planning requirements identified in Order No. 1920. *Id.* P 914.

[1211] *See* Arizona Commission Rehearing Request at 16.

[1212] Order No. 1920, 187 FERC ¶ 61,068 at P 996 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 153 (''[T]he ultimate responsibility for transmission planning remains with . . . transmission providers.'')).

[1213] *Id.* P 996.

[1214] *Id.* P 996.

[1215] *See Zady Natey, Inc.* v. *United Food & Comm. Workers Int'l Union, Loc. No. 27,* 995 F.2d 496, 499–500 (4th Cir. 1993) (determining whether contractual counterparty made good faith efforts to perform obligation on the basis of facts developed in adjudicating contractual dispute); *Creative Mktg. Assocs., Inc.* v. *AT&T,* 476 F.3d 536, 538–39 (8th Cir. 2007) (same); *Zinn* v. *Parrish,* 644 F.2d 360, 366 (7th Cir. 1981) (same); *Taco Bell Corp.* v. *Bloor Auto., Inc.,* No. 90–1442, 1991 WL 11618, at *6 (6th Cir. Feb. 5, 1991) (same); *Gulati* v. *Coyne Int'l Enters. Corp.,* 805 F.Supp. 365, 370–71 (E.D. Va. 1992) (same).

[1216] *Reasonable Efforts,* Black's Law Dictionary (12th ed. 2024).

[1217] As the Commission explained in Order No. 1920, however, the transmission provider's failure to obtain Relevant State Entities' support is not necessarily evidence that transmission providers did not exercise good faith efforts to seek their support. Order No. 1920, 187 FERC ¶ 61,068 at P 997.

[1218] *Id.* P 1012.

[1219] *Id.*

[1220] *Id.* P 1013.

[1221] *Id.*

otherwise is prohibiting voluntary funding in other circumstances.[1222]

c. Commission Determination

465. In response to SERTP Sponsors' request for clarification, we reiterate that Order No. 1920 does not prohibit voluntary funding approaches that are not described therein.[1223] Transmission providers may seek to demonstrate on compliance that other voluntary funding approaches are consistent with or superior to Order No. 1920's requirements, or they may submit a filing under FPA section 205 to propose such approaches.[1224]

4. No Selection Requirement

a. Order No. 1920 Requirements

466. In Order No. 1920, the Commission stated that it would not require transmission providers to select any particular Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria.[1225] The Commission also prohibited transmission providers from adopting 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.[1226]

b. Requests for Rehearing and Clarification

467. SERTP Sponsors request clarification that the Commission's statement, *i.e.,* 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,'' does not undercut the Commission's determination that Order No. 1920 does not require a transmission provider to select any Long-Term Regional Transmission Facility, even where it meets the transmission provider's selection criteria.[1227] PJM also requests that the Commission clarify that PJM is not required to select Long-Term Regional Transmission Facilities under any of the Long-Term Scenarios that it develops.[1228]

c. Commission Determination

468. In response to SERTP Sponsors' and PJM's requests for clarification, we clarify that Order No. 1920 does not require transmission providers to select any Long-Term Regional Transmission Facility, even where it meets the transmission providers' selection criteria.[1229]

5. Reevaluation

a. NOPR Proposal

469. 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.[1230] The Commission proposed that, to the extent the Relevant State Entities in a transmission planning region agree to a State Agreement Process, the development schedule should also include relevant steps related to that process.[1231]

470. 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.[1232]

b. Order No. 1920 Requirements

471. In Order No. 1920, the Commission required transmission providers to include in their OATTs provisions that require them to reevaluate previously selected Long-Term Regional Transmission Facilities in three situations, where: (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; (2) the actual or projected costs of a previously selected Long-Term Regional Transmission Facility significantly exceed cost estimates used in that Long-Term Regional Transmission Facility's selection; 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 provider's selection criteria.[1233] The Commission further required transmission providers to include in these reevaluation provisions the specific criteria they will use to determine when one of these situations occurs.[1234]

472. With respect to reevaluation on the basis of development delays, the Commission explained that Order No. 1920's requirement is the same requirement as that set forth by the

[1222] SERTP Sponsors Rehearing Request at 8. SERTP Sponsors further contend that, if the Commission fails to clarify that Order No. 1920 does not prohibit voluntary funding in other circumstances, Order No. 1920 would be arbitrary and capricious and exceed the Commission's authority. *Id.*

[1223] Order No. 1920, 187 FERC ¶ 61,068 at P 1017.

[1224] *Id.* It is unclear whether SERTP Sponsors intended to argue that failure to grant clarification in this respect would result in Order No. 1920 exceeding the Commission's authority; to the extent they intended to do so, we find this argument has not been raised with the specificity required on rehearing. *See supra* Major Questions Doctrine section.

[1225] Order No. 1920, 187 FERC ¶ 61,068 at P 1026 (citations omitted).

[1226] *Id.* P 968.

[1227] SERTP Sponsors Rehearing Request at 9–10 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 968, 1026).

[1228] PJM Rehearing Request at 19.

[1229] Order No. 1920, 187 FERC ¶ 61,068 at P 1026.

[1230] 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 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. The Commission stated that 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 No. 1000–A, 139 FERC ¶ 61,132 at P 442.

[1231] NOPR, 179 FERC ¶ 61,028 at P 247.

[1232] *Id.* P 248.

[1233] Order No. 1920, 187 FERC ¶ 61,068 at PP 1048–1049.

[1234] *Id.* P 1050.

Commission in Order No. 1000.[1235] The Commission explained that, as is required for regional transmission planning processes under Order No. 1000, transmission providers 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.[1236]

473. The Commission provided transmission providers with the flexibility to develop these reevaluation criteria[1237] provided that, with respect to reevaluation on the basis of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations, transmission providers may not reevaluate a previously selected Long-Term Regional Transmission Facility unless its targeted in-service date was in the latter half of the 20-year transmission planning horizon when it was selected.[1238] The Commission also required that the reevaluation criteria seek to maximize benefits accounting for costs over time without over-building transmission facilities. The Commission further explained that it expected transmission providers to 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.[1239] The Commission also required transmission providers to designate a point after which all selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation—*e.g.,* when the facility's transmission developer has secured all relevant permits and authorizations—such that the transmission developer of the selected Long-Term Regional Transmission Facility has adequate certainty to make investment decisions.[1240]

474. The Commission further required transmission providers to include in their OATTs provisions detailing the process and procedures 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, or removing the Long-Term Regional Transmission Facility from the regional transmission plan), and in particular the conditions under which they would remove a previously selected Long-Term Regional Transmission Facility from the regional transmission plan.[1241]

475. The Commission otherwise allowed flexibility as to the design of the reevaluation processes and procedures, subject to three requirements.[1242] First, the Commission stated that any reevaluation on the basis of cost increases or of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations must occur in a subsequent Long-Term Regional Transmission Planning cycle and must take into account not only the updated costs but also the updated benefits of the Long-Term Regional Transmission Facility.[1243] The Commission stated that, when performing these reevaluations, it expected 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.[1244] Second, the Commission required transmission providers to include in the reevaluation processes and procedures mechanisms for tracking the costs of Long-Term Regional Transmission Facilities.[1245] Third, the Commission required that the reevaluation processes and procedures seek to maximize benefits accounting for costs over time without over-building transmission facilities.[1246]

c. Requests for Rehearing and Clarification

i. Logical Outgrowth

476. Several parties argue that the Commission did not provide sufficient notice of, and opportunity to comment on, Order No. 1920's reevaluation requirements.[1247] For example, EEI claims that the Commission cannot require transmission providers to adopt OATT provisions that require them to reevaluate previously selected Long-Term Regional Transmission Facilities without providing notice of and an opportunity to comment on these requirements.[1248] EEI argues that Order No. 1920's reevaluation requirements are not within the scope of the NOPR's reevaluation proposal and therefore were not ''reasonably foreseeable'' by interested parties and that these requirements cannot stand because they are not a logical outgrowth of the NOPR proposal.[1249] EEI notes that the Commission stated in Order No. 1920 that a number of parties expressed support for the reevaluation requirements in their NOPR comments but contends that applicable precedent makes clear that comments on the proposed rule are not a substitute for the Commission itself providing notice of its intention to impose these requirements.[1250] EEI further notes that the Commission has invited consideration of the reevaluation of previously selected transmission facilities in a different proceeding and states that it would have been more appropriate for the Commission to have acted in that proceeding rather than in Order No. 1920 because the NOPR lacked any description of the range of reevaluation alternatives.[1251] EEI states that it does not oppose ''reasonable mechanisms'' to protect consumers from over-building Long-Term Regional Transmission Facilities and from the possibility of building transmission

[1235] *Id.* P 1049 n.2250. *See id.* P 1033 & n.2224 (explaining that the Commission proposed in the NOPR that existing transmission developer requirements would apply to Long-Term Regional Transmission Planning and that, if a transmission facility's developer did not achieve development milestones, transmission providers may remove that facility from the regional transmission plan and reevaluate the regional transmission plan to seek an alternative solution).

[1236] *Id.* P 1056.

[1237] *Id.*

[1238] *Id.* P 1051.

[1239] *Id.* P 1050.

[1240] *Id.*

[1241] *Id.* P 1052 (citing MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § IX.E, which sets forth potential outcomes of MISO's variance analysis procedures).

[1242] *Id.*

[1243] *Id.; see also id.* P 1059 (explaining that the requirement that the reevaluation processes and procedures update not only actual and projected costs but also their calculation of the benefits of the selected Long-Term Regional Transmission Facility will ensure that transmission providers compare the updated costs and benefits when determining whether the Long-Term Regional Transmission Facility continues to be a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs).

[1244] *Id.* P 1052 n.2254.

[1245] *Id.* P 1052.

[1246] *Id.*

[1247] East Kentucky Rehearing Request at 1–2; EEI Rehearing Request at 4–11; ITC Rehearing Request at 16; MISO TOs Rehearing Request at 8, 19–22; NRECA Rehearing Request at 13–15, 22; WIRES Rehearing Request at 2–4, 6–16.

[1248] EEI Rehearing Request at 5.

[1249] *Id.* at 6–7 (citing *Brennan* v. *Dickson,* 45 F.4th at 69–70).

[1250] *Id.* (citing *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 549 (D.C. Cir. 1983)).

[1251] *Id.* at 10 (citing Notice Inviting Post-Technical Conference Comments, *Transmission Planning and Cost Mgmt.,* Docket No. AD22–8–000, et al. (Dec. 23, 2022)).

facilities that may not be cost-effective, but asserts that the appropriate remedy in this instance is to return to the NOPR proposal.[1252]

477. NRECA argues that Order No. 1920 departs from the NOPR proposal by adopting ''completely new'' requirements for the reevaluation of previously selected Long-Term Regional Transmission Facilities.[1253] NRECA contends that the reevaluation requirements result in an ''inflexible, final selection of Long-Term Regional Transmission Facilities for purposes of regional cost allocation in the first three years of each Long-Term Regional Transmission Planning cycle.'' [1254] NRECA recommends that, to ensure compliance with the APA's notice-and-comment requirements, the Commission withdraw the final rule and issue a supplemental NOPR.[1255]

478. WIRES asserts that the NOPR did not provide notice to interested parties of Order No. 1920's ''detailed and prescriptive'' reevaluation requirements and that these requirements represent major changes from the NOPR proposal.[1256] WIRES asserts that the reevaluation requirements are significant because they could lead to modifying Long-Term Regional Transmission Facilities or removing them from the regional transmission plan, and, as such, the Commission should have clearly and unambiguously set forth a proposal in the NOPR before adopting Order No. 1920's reevaluation requirements.[1257] WIRES alleges that instead, the Commission adopted ''almost word-for-word'' a proposal submitted in comments by Large Public Power without first providing notice of and an opportunity to comment on this proposal.[1258]

479. Several rehearing parties contend that, while the NOPR proposed a structure that would permit but not require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities, Order No. 1920 requires that transmission providers do so and includes a number of prescriptive requirements that were not included in the NOPR.[1259] MISO TOs argue that Order No. 1920 states that it adopted with modification the NOPR proposal, despite the fact that the NOPR proposed a ''flexible and open-ended opportunity'' in accordance with which transmission providers could have tailored their compliance proposals, whereas Order No. 1920's reevaluation requirements are ''a wholly new and tightly prescriptive process with new triggering events and new requirements for reassessing facilities.'' [1260] WIRES notes that the NOPR did not use the term ''reevaluate,'' that it proposed to provide flexibility for transmission providers to propose their own processes, and did not include any relevant details or requirements other than to propose that transmission providers ''should 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.'' [1261]

480. Several parties acknowledge that, in setting forth Order No. 1920's reevaluation requirements, the Commission cited the NOPR proposal that would have allowed transmission providers to make the selection status of previously selected Long-Term Regional Transmission Facilities subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles,[1262] but contend nonetheless that that notice was inadequate. EEI states that the NOPR proposal contained none of the detail or the rationale regarding specific elements of Order No. 1920's reevaluation requirements, such as the specific situations in which reevaluation would be required or the requirement for transmission providers to include in their OATTs the potential outcomes of reevaluation.[1263] EEI further argues that, whereas the NOPR proposal focused on how the outcome of subsequent Long-Term Regional Transmission Planning cycles could give rise to the need to reevaluate, the three situations in which Order No. 1920 requires reevaluation do not depend on the results of or actions in a subsequent Long-Term Regional Transmission Planning cycle.[1264]

481. NRECA states that it did not oppose the Commission's NOPR proposal to require transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning—and particularly, the requirements that transmission providers use a 20-year transmission planning horizon and measure the benefits of transmission facilities over 20 years—because of the NOPR proposal to allow transmission providers to subject the selection status of Long-Term Regional Transmission Facilities to the outcome of subsequent Long-Term Regional Transmission Planning cycles.[1265] NRECA states that it interpreted the NOPR as allowing transmission providers to develop selection criteria under which transmission providers could conditionally select a Long-Term Regional Transmission Facility but delay selecting that Facility for purposes of cost allocation until later.[1266] NRECA states that the Commission did not adopt the NOPR proposal and instead adopted ''completely different, prescriptive [reevaluation] requirements.'' [1267]

482. MISO TOs and ITC each argue that the Commission did not provide adequate notice of or an opportunity to comment on the requirement that transmission providers update their measurement of the benefits of Long-Term Regional Transmission Facilities. MISO TOs state that the NOPR proposed ''the option of a routine review'' and did not include any requirement for a ''general reevaluation of benefits of the facilities,'' and that this deprived regulated parties of the fair notice required by the APA.[1268] ITC contends that Order No. 1920's reevaluation requirements depart substantially from the original reevaluation proposal, and that the Commission has not provided commenters a meaningful opportunity to comment on the requirement ''to perform a full update of the calculation of the benefits'' resulting in a factual record that does not address the relative merits of this approach.[1269]

483. MISO TOs and WIRES each argue that, had the Commission provided notice of and an opportunity to comment, Order No. 1920's reevaluation requirements would ultimately have been improved. MISO TOs argue that Order No. 1920 is not as clear or as workable as it might have been if MISO TOs and other commenters had fair notice, and that the Commission instead could have adopted ''a more nuanced and workable requirement.'' [1270] WIRES claims that the Commission did not have the benefit of sufficient input from regulated

[1252] *Id.* at 10–11.

[1253] NRECA Rehearing Request at 4–6.

[1254] *Id.* at 14.

[1255] *Id.* at 4, 19.

[1256] WIRES Rehearing Request at 3–5.

[1257] *Id.* at 2–4.

[1258] *Id.* at 10.

[1259] *See, e.g.,* EEI Rehearing Request at 7–8; WIRES Rehearing Request at 7–8.

[1260] MISO TOs Rehearing Request at 21–22 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1048).

[1261] WIRES Rehearing Request at 6–7 (quoting NOPR, 179 FERC ¶ 61,028 at P 248).

[1262] *See* NOPR, 179 FERC ¶ 61,028 at P 248.

[1263] EEI Rehearing Request at 5–6.

[1264] *Id.* at 8–9.

[1265] NRECA Rehearing Request at 13 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

[1266] *Id.* at 24.

[1267] *Id.* at 25 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1055 & n.2257).

[1268] MISO TOs Rehearing Request at 19–21.

[1269] ITC Rehearing Request at 16.

[1270] MISO TOs Rehearing Request at 19, 22.

parties. WIRES contends that, while the Commission stated that it set forth Order No. 1920's reevaluation requirements having ''carefully reviewed the record developed here and weighed commenters' countervailing arguments,'' the comments submitted were specific to the NOPR proposal that was not adopted—not Order No. 1920's reevaluation requirements.[1271]

ii. Other Issues

484. Several parties sought rehearing or clarification of the requirement to update the measurement of benefits when reevaluating a previously selected Long-Term Regional Transmission Facility or Facilities.[1272] MISO TOs argued that the requirement for transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities risks significant disruption to the use of portfolio approaches to selecting such facilities. MISO TOs argued that the Commission had not provided substantial evidence to support requiring transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities during reevaluations, as the Commission acknowledged that updating the measurement of benefits is ''not as straightforward as tracking costs,'' reassessing benefits is different than reassessing costs, and reevaluation could create ''unnecessary disruptions and potentially impede the efficient conduct'' of Long-Term Regional Transmission Planning.[1273] MISO TOs requested that, on rehearing, the Commission modify Order No. 1920's requirement such that transmission providers would ''consider benefits and the broader needs of the region in the reevaluation process and choose an outcome based on that assessment.''[1274]

485. ITC argued that, while reevaluating a previously selected Long-Term Regional Transmission Facility on the basis of cost increases is reasonable, Order No. 1920's requirement for transmission providers to update their measurement of the benefits of Long-Term Regional Transmission Facilities will burden transmission providers and deter investment in such facilities. ITC therefore requested that the Commission eliminate the requirement to update the measurement of the benefits or, in the alternative, clarify that transmission providers may adopt a more qualitative assessment that takes into account the benefits and costs of a Long-Term Regional Transmission Facility in the context of the transmission planning region's Long-Term Transmission Needs, and also that transmission providers may adopt flexible remedial measures such as those available under MISO's variance analysis process.[1275] Similarly, WIRES requested clarification as to whether Order No. 1920 would allow transmission providers flexibility to determine how they will update their measurement of the benefits of Long-Term Regional Transmission Facilities, and argued that transmission providers should have the flexibility to address the concerns raised by the Commission in developing their reevaluation criteria in a manner compatible with their transmission planning process.[1276]

486. NRECA requested that the Commission eliminate the requirement for transmission providers to designate a point after which all previously selected Long-Term Regional Transmission Facilities will no longer be subject to reevaluation, *i.e.,* a pencils-down point, such that the transmission developer of the selected facility would have adequate certainty to make investment decisions.[1277]

487. Large Public Power and NRECA requested that the Commission require on rehearing that transmission providers reevaluate previously selected Long-Term Regional Transmission Facilities not only when there is a significant increase in costs, but also when there is a significant decrease in the benefits of a particular facility.[1278] Large Public Power further requested that the Commission clarify that Order No. 1920 requires transmission providers to track both the costs and the benefits of previously selected Long-Term Regional Transmission Facilities.[1279] In addition to reevaluation on the basis of cost increases, NRECA argued that transmission providers should be required to reevaluate previously selected Long-Term Regional Transmission Facilities when the transmission planning region's Long-Term Transmission Needs have changed.[1280]

488. ITC, Large Public Power, and NRECA argued that the Commission should grant rehearing and eliminate Order No. 1920's requirements to reevaluate on the basis of significant changes in federal, federally-recognized Tribal, state, or local laws or regulations, because these requirements are either too narrow or too broad.[1281]

489. ITC stated that Order No. 1920 encourages the use of portfolio approaches to select Long-Term Regional Transmission Facilities, as they generate considerable interdependency among the various Long-Term Regional Transmission Facilities selected in a particular Long-Term Regional Transmission Planning cycle. ITC therefore recommended that the Commission require periodic project portfolio reporting modeled after MISO's Multi-Value Project Triennial Reporting framework, which ITC contended provides a regular check to ensure transmission customers receive the benefits they are promised and allows for regional transmission planning process improvement.[1282] If the Commission did not grant rehearing and eliminate reevaluations on the basis of significant changes in law or regulations, ITC requested that the Commission allow such reevaluation only for Long-Term Regional Transmission Facilities whose targeted in-service date is more than 10 years from the point at which the transmission provider conducts the reevaluation.

490. In contrast, Large Public Power argued that the ''blanket ten-year moratorium'' is arbitrary and capricious.[1283] NRECA argued that the Commission provided no rationale for this limitation, which it characterized as ''so implausible that it could not be ascribed to a difference in view or the product of agency expertise.''[1284]

491. Several parties requested that the Commission provide transmission providers with more flexibility to reevaluate previously selected Long-Term Regional Transmission Facilities in other situations. Dominion sought

[1271] WIRES Rehearing Request at 14–16 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1053).

[1272] MISO TOs Rehearing Request at 4; ITC Rehearing Request at 17; WIRES at 11–12.

[1273] MISO TOs Rehearing Request at 17–19 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1059).

[1274] *Id.* at 13.

[1275] ITC Rehearing Request at 15–19.

[1276] WIRES Rehearing Request at 14.

[1277] NRECA Rehearing Request at 33 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1050); *see also* East Kentucky Rehearing Request at 2 (arguing that Order No. 1920 permits arbitrary and unreasonable deadlines on reevaluations).

[1278] Large Public Power Rehearing Request at 17–19; NRECA Rehearing Request at 29–30; *see also* East Kentucky Rehearing Request at 2 (arguing that the Order No. 1920 requirement related to reevaluation on the basis of cost increases is ''too narrowly drawn'' and inconsistent with other aspects of Order No. 1920).

[1279] Large Public Power Rehearing Request at 17–18 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 1054, 1059).

[1280] NRECA Rehearing Request at 30–32.

[1281] ITC Rehearing Request at 4–5; Large Public Power Rehearing Request at 19–20; NRECA Rehearing Request at 36; *see also* East Kentucky Rehearing Request at 2 (stating that Order No. 1920 ''arbitrarily [and] unreasonably prohibits some reevaluations due to changes in laws or regulations'').

[1282] ITC Rehearing Request at 13–14.

[1283] Large Public Power Rehearing Request at 19–20.

[1284] NRECA Rehearing Request at 36 (quoting *State Farm,* 463 U.S. at 43).

rehearing or, as applicable, clarification of the Commission's reevaluation process to allow transmission providers to reevaluate a previously selected Long-Term Regional Transmission Facility in situations other than those identified in Order No. 1920.[1285] Similarly, SERTP Sponsors requested that the Commission clarify that the three situations described in Order No. 1920 in which reevaluation of previously selected Long-Term Regional Transmission Facilities is required are illustrative, arguing that Order No. 1920 grants transmission providers inadequate flexibility in developing OATT provisions regarding the reevaluation of previously selected Long-Term Regional Transmission Facilities.[1286]

d. Commission Determination

i. Logical Outgrowth

492. We disagree with the argument that the Commission failed to provide adequate notice of and opportunity to comment on Order No. 1920's requirement that transmission providers include provisions in their OATTs that require them to reevaluate previously selected Long-Term Regional Transmission Facilities in certain circumstances. As the D.C. Circuit explained recently, ''the very premise of agencies' duty to solicit, consider, and respond appropriately to comments is that rules evolve from conception to completion.'' [1287] Indeed, notice is sufficient if the final rule represents a ''logical outgrowth'' of the proposed rule.[1288] Order No. 1920's reevaluation requirements are closely related to and fully in character with the NOPR proposal, and represent the kind of reasonable evolution of an initial proposal in response to comments that rehearing parties could have reasonably anticipated.

493. As an initial matter, we note that the NOPR proposed to require the reevaluation of previously selected transmission facilities in certain circumstances. Because Long-Term Regional Transmission Planning is a form of regional transmission planning,[1289] the Commission's regional transmission planning requirements apply. This includes a requirement that transmission providers describe in their OATTs the circumstances in which and the procedures under which transmission providers will conduct a reevaluation. This reevaluation is necessary to determine how a transmission provider will respond if development delays affecting a previously selected regional transmission facility jeopardize incumbent transmission owners' ability to meet their reliability needs or service obligations.[1290] The Commission made this explicit in the NOPR when it proposed that Order No. 1000's transmission developer requirements would apply to Long-Term Regional Transmission Planning [1291] and noted that in the event of development delays, transmission providers may ''remove the transmission facility from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.'' [1292]

494. The Commission further proposed in the NOPR to allow transmission providers to make the selection status of a previously selected Long-Term Regional Transmission Facility ''subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles,'' such that it ''is no longer needed'' and proposed that transmission providers ''should 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.'' [1293] The Commission suggested that this proposal was warranted because the development schedule for a Long-Term Regional Transmission Facility may not require its developer to undertake actions or incur expenses in the near-term,[1294] and it explained that the NOPR's proposed reforms were intended to be responsive to ''commenters' concerns about over-building [transmission facilities] due to uncertainties of future transmission system conditions.'' [1295] Therefore, although the Commission used other language, the Commission effectively proposed in the NOPR that transmission providers could reevaluate certain Long-Term Regional Transmission Facilities (*i.e.,* those for which near-term development activities are not necessary) in light of changed circumstances apparent in the subsequent Long-Term Regional Transmission Planning cycle to determine whether to continue developing that facility or find that it was no longer needed.[1296]

495. In other words, the NOPR provided adequate notice of and an opportunity to comment on proposals to require reevaluation of previously selected Long-Term Regional Transmission Facilities due to development delays and to permit reevaluation of previously selected Long-Term Regional Transmission Facilities due to changed circumstances from one Long-Term Regional Transmission Planning cycle to the next.

496. Commenters objected to the NOPR proposal on the grounds that providing open-ended allowance for reevaluation of previously selected Long-Term Regional Transmission Facilities would undermine selection as a ''reasonably final'' step and create too much uncertainty for transmission developers, which would impede the development of the relevant transmission facilities and ultimately could raise concerns about reliability impacts or other consequences.[1297] Upon consideration of the record before it and these comments in particular, the Commission modified the NOPR proposal to allow for the reevaluation of previously selected Long-Term Regional Transmission Facilities due to changed circumstances from one transmission planning cycle to the next. Specifically, Order No. 1920 required the reevaluation of Long-Term Regional Transmission Facilities only in certain circumstances that could affect the need for the facility—*i.e.,* where the costs of the transmission facility significantly exceed estimates or where significant changes in federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that the facility no longer meets selection criteria.[1298] Further, consistent with the Commission's reasoning in the NOPR that reevaluation may be appropriate where near-term development actions or expenditures are not needed in order to meet the targeted in-service date, the Commission limited the availability of reevaluation due to significant changes in laws or regulations to only those facilities that are not needed to be in-service within 10 years (*i.e.,* unless its

[1285] Dominion Rehearing Request at 17.

[1286] SERTP Sponsors Rehearing Request at 20–21.

[1287] *Brennan* v. *Dickson,* 45 F.4th at 69.

[1288] *Long Island Care,* 551 U.S. at 174–75. *See also Am. Paper Inst.* v. *EPA,* 660 F.2d at 959 n.13 (''An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.'') (emphasis added).

[1289] NOPR, 179 FERC ¶ 61,028 at P 68; Order No. 1920, 187 FERC ¶ 61,068 at P 224.

[1290] Order No. 1000, 136 FERC ¶ 61,051 at P 329.

[1291] NOPR, 179 FERC ¶ 61,028 at P 247.

[1292] *Id.* P 247 n.395 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 442).

[1293] *Id.* P 248.

[1294] *Id.*

[1295] NOPR, 179 FERC ¶ 61,028 at P 245.

[1296] *Id.* P 248.

[1297] Order No. 1920, 187 FERC ¶ 61,068 at P 1055 & n.2256.

[1298] *Id.* PP 1048–1055.

targeted in-service date was in the latter half of the 20-year transmission planning horizon during the Long-Term Regional Transmission Planning cycle in which it was selected) and required a ''pencils-down'' point in the development of a facility at which reevaluation would no longer be permitted.[1299] The Commission's modifications are not ''surprisingly distant'' from the proposal so as to be wholly unexpected; [1300] instead, the changes merely refine the proposals included in the NOPR and are thus precisely the kind of tailoring and fine-tuning of a proposed rule in response to comments that is the *raison d'être* for APA notice-and-comment requirements.[1301]

ii. Other Issues

497. We also disagree with rehearing parties' substantive objections to the reevaluation requirements. While certain parties object to the reevaluation requirements as too lax,[1302] and other parties object to them as too stringent,[1303] we conclude that they strike a reasonable balance between providing adequate certainty to transmission developers to support capital investment, such that more efficient or cost-effective Long-Term Transmission Facilities actually may be developed, and mitigating the inherent uncertainty involved in Long-Term Regional Transmission Planning, given that continued selection of Long-Term Regional Transmission Facilities that no longer meet selection criteria could be costly to consumers.[1304] Specifically, though several rehearing parties object that reevaluation should be required in additional circumstances, such as whenever there is a reduction in benefits,[1305] whenever there is a change in transmission needs,[1306] or at points of time beyond the ''pencils-down'' date,[1307] and others argue that the transmission provider should have more discretion to determine when to reevaluate previously selected Long-Term Regional Transmission Facilities,[1308] we continue to find that such open-ended allowance for reevaluation would fail to account for the degree of certainty that is needed to support capital investment, and would therefore fail to adequately ensure development of more efficient or cost-effective Long-Term Regional Transmission Facilities.[1309]

498. On the other hand, we also reject requests to eliminate the requirement to reevaluate facilities where significant changes in laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission provider's selection criteria.[1310] We remain concerned that, absent an opportunity to determine whether selection of such a facility remains warranted in light of a significant change in laws or regulations, transmission providers may be reluctant to select certain Long-Term Regional Transmission Facilities,[1311] and we find that requiring reevaluation in such a circumstance helps to mitigate the inherent uncertainty of Long-Term Regional Transmission Planning and the risk of over-building transmission facilities. With the limitations we impose—*i.e.,* that such reevaluation only occur for facilities with a targeted in-service date that is in the latter half of the Long-Term Regional Transmission Planning cycle in which it is selected and that reevaluation may only occur up to the ''pencils-down'' point in the facility's development—we are not persuaded that reevaluation under these circumstances will create such uncertainty for transmission developers as to significantly impede the development of more efficient of cost-effective Long-Term Regional Transmission Facilities.

499. While we appreciate rehearing parties' concerns that assessing a change in a transmission facility's benefits is more complex than assessing a change in its costs, we decline requests to set aside the requirement to account for updated benefits when transmission providers reevaluate a Long-Term Regional Transmission Facility based on a significant increase in the facility's estimated costs.[1312] We continue to find that such a requirement will help to ensure there is an opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities, because otherwise the transmission provider would compare the facility's currently determined costs with its previously determined benefits.[1313]

500. We further find that rehearing parties' concerns about the burdens of accounting for updated benefits are misplaced, as Order No. 1920 provided significant flexibility to transmission providers as to how to account for changes in benefits. While Order No. 1920 requires that such reevaluations must only occur during a subsequent Long-Term Regional Transmission Planning cycle (*i.e.,* rather than in between such cycles) because doing so during such a cycle enables transmission providers to make use of updated assumptions, inputs, and the Long-Term Scenarios that must be developed in any event during the subsequent cycle, Order No. 1920 does not prescribe any particular method for assessing updated benefits.[1314] We note that, because Order No. 1920 provides transmission providers the flexibility to propose qualitative measures in their evaluation processes and qualitative selection criteria, transmission providers will need flexibility to develop a process for determining if a previously selected Long-Term Regional Transmission Facility continues to meet those selection criteria.

501. We are also not persuaded by rehearing parties' arguments that the reevaluation requirements will undermine the ability of transmission providers to use a portfolio approach to evaluating benefits or selecting Long-Term Regional Transmission Facilities.[1315] As described above, transmission providers have significant flexibility to determine how to update benefits, and they may propose to use a method that accommodates Order No. 1920's reevaluation requirements in the context of portfolio approaches to selecting Long-Term Regional Transmission Facilities. Likewise, provided the process seeks to maximize benefits accounting for costs over time without over-building transmission facilities, transmission providers have significant flexibility to determine the appropriate outcomes that may result from reevaluation, including the potential mitigation measures that may

[1299] *Id.* PP 1050–1051.

[1300] *Brennan* v. *Dickson,* 45 F.4th at 69.

[1301] We note that, while the reevaluation requirements are one tool to manage the inherent uncertainties of Long-Term Regional Transmission Planning and to limit the risk of over-building transmission in response to speculative transmission needs, we believe that other requirements in Order No. 1920 also address these concerns. The inability to include reevaluation requirements would not have prevented the Commission from issuing Order No. 1920.

[1302] *See e.g.,* East Kentucky Rehearing Request at 2; NRECA Rehearing Request at 33.

[1303] *See e.g.,* ITC Rehearing Request at 15–19; MISO TOs Rehearing Request at 17–19.

[1304] Order No. 1920, 187 FERC ¶ 61,068 at P 1054.

[1305] Large Public Power Rehearing Request at 17–19; NRECA Rehearing Request at 29–30.

[1306] NRECA Rehearing Request at 30–32.

[1307] *Id.* at 33.

[1308] Dominion Rehearing Request at 17; SERTP Sponsors Rehearing Request at 20–21.

[1309] Order No. 1920, 187 FERC ¶ 61,068 at P 1053.

[1310] ITC Rehearing Request at 4–5.

[1311] Order No. 1920, 187 FERC ¶ 61,068 at P 1056.

[1312] MISO TOs Rehearing Request at 17–19; ITC Rehearing Request at 15–19.

[1313] Order No. 1920, 187 FERC ¶ 61,068 at P 1059.

[1314] This clarification resolves WIRES's request for clarification regarding the flexibility allowed transmission providers to determine how to account for updated benefits. *See* WIRES Rehearing Request at 14.

[1315] ITC Rehearing Request at 6–9; MISO TOs Rehearing Request at 17–19.

be regionally appropriate.[1316] Thus, transmission providers have scope to tailor both how reevaluation is conducted and the outcomes of the reevaluation process to the portfolio approach.

E. Implementation of Long-Term Regional Transmission Planning

1. Order No. 1920 Requirements

502. In Order No. 1920, the Commission required transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. The Commission required transmission providers to provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, the Commission required transmission providers to address the possible interaction between the transmission planning cycles for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. The Commission recognized 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.[1317] Second, the Commission required transmission providers to address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. The Commission recognized that 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.[1318]

503. The Commission found 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. However, the Commission expressed concern 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, the Commission required 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 the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. The Commission stated that 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 align the Long-Term Regional Transmission Planning cycle with existing transmission planning cycles.[1319] While the Commission encouraged transmission providers to align transmission planning cycles if useful, to ensure that there is no inappropriate delay to starting Long-Term Regional Transmission Planning, the Commission stated that 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.[1320]

504. The Commission encouraged transmission providers to address in their explanations 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.[1321]

2. Requests for Rehearing and Clarification

505. PJM states that it recognizes that the long-term transmission planning horizon can and will inform Order No. 1000 processes but argues that it is imperative that these two processes function effectively together so that PJM can respond to short-term needs quickly and nimbly.[1322] Accordingly, PJM requests flexibility in designing its Long-Term Regional Transmission Planning process in a way that would minimize harmful interaction from the overlap between Order No. 1000 and Order No. 1920 regional transmission planning processes and would allow for the efficient use of PJM's resources.[1323]

506. TAPS asserts that Order No. 1920 does not adequately clarify how the Order No. 1000 economic and reliability processes and the Long-Term Regional Transmission Planning process will interact after the initial implementation phase.[1324] TAPS argues that Order No. 1920 does not address whether, or the circumstances under which, transmission projects may be moved from an Order No. 1000 reliability or economic planning process to the Long-Term Regional Transmission Planning process, or vice versa.[1325] As a result, TAPS requests that the Commission recognize that these regional transmission planning processes will continue to interact after the initial implementation of Long-Term Regional Transmission Planning and require that transmission providers demonstrate how these processes will interact on an ongoing basis, including how and when transmission projects may be moved between the two processes.[1326]

3. Commission Determination

507. As an initial matter, upon further consideration, we set aside, in part, Order No. 1920's requirement that transmission providers in each transmission planning region must propose on compliance a date, no later than one year from the date on which initial filings to comply with the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle.[1327] Instead, we require that transmission providers must propose on compliance a date, no later than *two* years from the date on which initial filings to comply with Order No. 1920 are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. We find that this modification balances the need to ensure that transmission providers timely implement Order No. 1920's requirements to avoid unnecessary delay in realizing these beneficial reforms for customers, as explained in Order No. 1920,[1328] with the need to provide transmission providers with sufficient time to implement Long-Term Regional Transmission Planning and align the Long-Term Regional Transmission Planning cycle with existing

[1316] Order No. 1920, 187 FERC ¶ 61,068 at P 1052.

[1317] *Id.* P 1071.

[1318] *Id.*

[1319] *Id.* P 1072.

[1320] *Id.*

[1321] *Id.* P 1073.

[1322] PJM Rehearing Request at 41.

[1323] *Id.*

[1324] TAPS Rehearing Request at 6–9.

[1325] *Id.* at 8.

[1326] *Id.* at 6–9.

[1327] Order No. 1920, 187 FERC ¶ 61,068 at P 1072.

[1328] *See id.*

transmission planning cycles, which may be longer than a single year.

508. Moreover, we modify Order No. 1920's requirement that transmission providers 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.[1329] Instead, we require that regardless of the date that transmission providers propose on compliance, they must explain in their compliance filing why the proposed date on which they will commence the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region. We find that this modification will allow the Commission to ensure that the proposed date will not unnecessarily delay the realization of Order No. 1920's beneficial reforms for customers.

509. We sustain the requirement that transmission providers must explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning will interact with the existing regional transmission planning processes under Order No. 1000. As the Commission recognized in Order No. 1920, there may be overlap in the time horizons for these processes, and 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.[1330] While Long-Term Regional Transmission Planning processes must still meet all requirements set forth in Order No. 1920, we believe that this flexibility extends to and addresses concerns raised by PJM, including its request for flexibility to design its Long-Term Regional Transmission Planning process in a way that minimizes potential harmful impacts to existing regional transmission planning processes.

510. In response to TAPS' request for rehearing, we recognize that Long-Term Regional Transmission Planning and existing Order No. 1000 economic and reliability transmission planning processes may continue to interact after the initial implementation of Long-Term Regional Transmission Planning. However, while this interaction is possible, we believe that, after the first Long-Term Regional Transmission Planning cycle concludes, the overlap between the existing Order No. 1000 regional transmission planning processes and Long-Term Regional Transmission Planning will likely diminish. As the Commission found in Order No. 1920, existing regional transmission planning processes that plan for reliability and economic transmission needs may in the future come to address only residual needs not already addressed through Long-Term Regional Transmission Planning.[1331] As a result, the potential for overlap between Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning process should decrease. Further, we do not believe that it is necessary to require transmission providers to explain how a transmission facility selected in one regional transmission process may ''move'' to another regional transmission planning process. Nevertheless, as the Commission stated in Order No. 1920, we encourage transmission providers to address in their explanation on compliance how their proposed Long-Term Regional Transmission Planning process will facilitate moving beyond piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.[1332]

VI. Coordination of Regional Transmission Planning and Generator Interconnection Processes

A. Need for Reform and Overall Requirement

1. Order No. 1920 Requirements

511. In Order No. 1920, the Commission found 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).[1333] The Commission made this finding in response to (among other things) evidence in the record that the level of spending on interconnection-related network upgrades has dramatically increased in recent years and evidence that this trend leads to more interconnection requests withdrawing in the face of significant costs associated with interconnection-related network upgrades.[1334] The Commission stated that, 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.[1335] The Commission also based its finding on evidence that in many cases when an 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.[1336]

512. Consequently, the Commission adopted requirements for transmission providers in each transmission planning region to revise their regional transmission planning processes in their OATTs to evaluate for selection regional transmission facilities that address certain interconnection-related transmission needs associated with specific interconnection-related network upgrades originally identified through the generator interconnection process. In particular, the Commission adopted four qualifying criteria for when transmission providers must evaluate interconnection-related transmission needs in the regional transmission planning process. The Commission found 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. The Commission stated that, as a result, this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.[1337]

[1329] *See id.*

[1330] *Id.*

[1331] *Id.* P 245.

[1332] *Id.* P 1073.

[1333] Order No. 1920, 187 FERC ¶ 61,068 at P 1100.

[1334] *Id.* P 1101.

[1335] *Id.*

[1336] *Id.* P 1102.

[1337] *Id.* PP 1106, 1145.

2. Requests for Rehearing

513. SERTP Sponsors, Large Public Power, and Industrial Customers argue that this reform is premature in light of Order No. 2023, which is intended to, among other things, reduce speculative interconnection requests and withdrawals.[1338] SERTP Sponsors argue that the Commission should grant rehearing and revisit this reform after experience is gained to determine whether interconnection withdrawals could ''reasonably be expected to be indicative of a need for new regional transmission facilities that have 'a voltage of at least 200 kV and an estimated cost of at least $30 million.' '' [1339] SERTP Sponsors argue that accordingly, the Commission has not established a rational basis supported by substantial evidence for this requirement.[1340]

514. PJM argues that the Commission failed to provide substantial evidence for its conclusion that, nationwide, the deciding factor for interconnection customers' withdrawals is sticker shock at their assigned network upgrade costs.[1341] PJM argues that the Commission ignored its analysis of more than 700 interconnection requests in one transmission zone over a six-year period that demonstrated that only 14 requests or 2% would have likely met the voltage and cost thresholds in Order No. 1920 and that nine of the 14 withdrew before a feasibility study was issued. Additionally, PJM argues that, of the remaining five, two were ultimately responsible for network upgrades of less than $30 million, thus leaving only three interconnection requests potentially withdrawing due to the cost of network upgrades.[1342] PJM argues that this data suggesting a withdrawal rate of less than one half percent in a large sample indicates insignificant correlation between network upgrade costs, voltage level, and business decisions to withdraw.[1343]

515. PJM further argues that, on the other hand, over the past six years, several dozen generation projects that executed interconnection agreements had associated network upgrades of less than $5 million but nonetheless terminated their interconnection agreements. Thus, PJM argues that factors other than sticker shock are common reasons for delay or failure to advance.[1344] PJM argues that the Commission disregarded this evidence and relied on studies in MISO and SPP to justify a one-size-fits-all approach, and it argues that this decision was arbitrary and capricious.[1345] NRECA argues that if the Commission believes that its existing generator interconnection polices are unjust and unreasonable and impose barriers to generation development, it should develop the appropriate evidentiary record, make the required findings, and direct a just and reasonable replacement policy.[1346]

3. Commission Determination

516. We continue to find that this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.[1347] While SERTP Sponsors, Large Public Power, and Industrial Customers argue that this reform is premature in light of Order No. 2023, we find that the scope of the Order No. 1920 coordination reform operates independently of, and is more limited than, the Order No. 2023 reforms. Order No. 2023 adopts reforms to the generator interconnection process through changes to the *pro forma* generation interconnection procedures and agreements. By comparison, Order No. 1920 adopts no changes to the generator interconnection process and instead implements the coordination reform through changes to the transmission planning process and the *pro forma* OATT.

517. Additionally, the purpose of the coordination reform in Order No. 1920 is to address a specific problem—insufficient coordination between the 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.[1348] Order No. 1920 recognizes the generator interconnection process is unlikely to result in the construction of transmission facilities that resolve such interconnection-related transmission needs because of the rate of withdrawal from the interconnection queue, due at least in part to interconnection customers' cost responsibility for expensive interconnection-related network upgrades.[1349] While Order No. 2023 aims to fix inefficiencies in the generator interconnection process, it does not direct any reforms regarding specific interconnection-related network upgrades that are unlikely to be developed.

518. The Commission reasonably concluded that reforms regarding these types of network upgrades are better addressed through improvement of coordination between the generator interconnection and regional transmission planning processes. The purpose of the Order No. 1920 coordination reform is to (1) require evaluation of regional transmission facilities that address certain (*i.e.,* that qualify under the criteria established in Order No. 1920) interconnection-related transmission needs associated with specific interconnection-related network upgrades in existing Order No. 1000 regional transmission planning and cost allocation processes to determine whether to select such facilities in the regional transmission plan for purposes of cost allocation, and (2) determine whether such facilities may address other regional transmission needs more efficiently or cost-effectively. For a limited set of interconnection-related transmission needs, this reform will allow transmission providers to identify, evaluate, and select the more efficient or cost-effective regional transmission solution independent of the success or failure of a particular interconnection request in the generator interconnection process. Additionally, if this requirement is triggered (*i.e.,* because interconnection-related network upgrades meet all of the established qualifying criteria), that is an indication of the continued existence of the concerns described in Order No. 1920, namely a barrier to entry in locations that, absent sticker shock, are ''otherwise desirable for generators to locate.'' [1350] Moreover, it may be that eventually, as a result of Order No. 2023, fewer withdrawals from the generator interconnection queue occur and that this provision is triggered less often. Further, there may be fewer instances of this requirement as the Order No. 1920 Long-Term Regional Transmission Planning process proactively addresses transmission needs related to generation additions on a forward-looking basis. These

[1338] SERTP Sponsors Rehearing Request at 22; Large Public Power Rehearing Request at 23; Industrial Customers Rehearing Request at 46–47.

[1339] SERTP Sponsors Rehearing Request at 22 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1145).

[1340] *Id.* at 22–23 (citing *Samaritan Health Serv.* v. *Bowen,* 811 F.2d 1524, 1528 (D.C. Cir. 1987) (finding that agency's classification of costs had ''no rational basis'' and was, therefore, arbitrary and capricious)).

[1341] PJM Rehearing Request at 31.

[1342] *Id.*

[1343] *Id.*

[1344] PJM Rehearing Request at 32.

[1345] *Id.* at 32 (citing 5 U.S.C. 706(2); 16 U.S.C. 825l(b); *S.C. Pub. Serv. Auth.,* 762 F.3d at 66–67; *TAPS,* 225 F.3d at 687; *Env't Def. Fund,* 2 F.4th 953).

[1346] NRECA Rehearing Request at 48–49.

[1347] Order No. 1920, 187 FERC ¶ 61,068 at P 1106.

[1348] *Id.* P 1100.

[1349] *See id.* P 1108.

[1350] *Id.* P 1103.

developments would not, however, address the present concerns that necessitate this coordination requirement. Given the low administrative burden associated with this reform,[1351] we conclude that its potential benefits outweigh the costs.

519. We disagree with PJM's claim that the Commission does not provide substantial evidence to demonstrate that existing Order No. 1000 regional transmission planning and cost allocation processes do not adequately address interconnection-related transmission needs associated with withdrawn interconnection requests. PJM's claim is unpersuasive because, as explained above, the Commission has sufficiently demonstrated the need for reform.

520. The Commission in Order No. 1920 also explained why it is appropriate to establish the coordination requirement in existing Order No. 1000 regional transmission planning and cost allocation processes, stating that:

> 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.[1352]

521. Further, courts have recognized the Commission can rely on general findings of systemic conditions to impose an industry-wide remedy under FPA section 206.[1353] The Commission found that there was substantial evidence to conclude 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).[1354]

522. We also are not persuaded by the evidence that PJM presented in this proceeding, which it argues demonstrates that only a small fraction of network upgrades that are the subject of its analysis would meet the voltage and cost thresholds established by Order No. 1920. We do not reach the same conclusions as PJM for multiple reasons. To begin, PJM's evidence pertains only to the Dominion zone in PJM from 2014 to 2020 and is not necessarily reflective of circumstances across the region, or nationwide, or over different time periods. Further, in Order No. 1920, the Commission cited to evidence from the record to support the conclusion that, in recent years, sticker shock over an interconnection customer's assigned network upgrade costs is often the deciding factor that leads to that interconnection customer's withdrawal of its interconnection request.[1355] For instance, the Commission cited analysis from a report showing that 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.[1356]

523. We also disagree with PJM's interpretation of its data, namely the claim that there is no need for reform because the data shows that the number of withdrawals due to sticker shock is small. PJM's reasoning suggests that the Commission found that sticker shock is only ever a deciding factor for an interconnection request's withdrawal if the withdrawn interconnection request was allocated interconnection-related network upgrade costs of $30 million or more or has a voltage of at least 200 kV (*i.e.,* the cost and voltage thresholds established by Order No. 1920 to limit the applicability of this new requirement). However, the Commission did not suggest that interconnection-related network upgrades below this cost threshold or below the 200 kV voltage threshold do not cause sticker shock. Instead, the established qualifying criteria are intended to strike a reasonable balance between precision and workability.[1357] To accomplish this workability, the Commission adopted requirements that do not require evaluation in the existing Order No. 1000 regional transmission planning and cost allocation processes of all interconnection-related transmission needs that were not addressed because the corresponding interconnection request withdrew in part or entirely due to sticker shock. Instead, as the Commission stated in Order No. 1920, the established criteria are necessary to limit the scope of the requirement to interconnection-related transmission needs associated with high-cost interconnection-related network upgrades "that are likely to persist, . . . not unique to a single interconnection request, and . . . that have the potential to provide more widespread benefits to transmission customers." [1358] We again find that this targeted approach and criteria are "broad enough to capture interconnection-related network upgrades that are likely to produce benefits beyond the interconnection customer" while retaining flexibility for transmission providers.[1359]

524. In response to NRECA, we note that the focus of Order No. 1920 is to remedy deficiencies in the regional transmission planning and cost allocation requirements and not the generator interconnection process. Nonetheless, we reiterate the findings in Order No. 1920 that the repeated identification of interconnection-related network upgrades in the generator interconnection process is indicative of a "barrier to accessing the transmission system and [establishes] a known interconnection-related transmission need . . . [that] can hinder the timely development of new generation, thereby stifling competition in wholesale electricity markets and limiting access to lower-cost generation" and that 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." [1360]

B. Qualifying Criteria

1. Order No. 1920 Requirements

525. In Order No. 1920, the Commission required 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

[1351] *See id.* P 1113.

[1352] *Id.* P 1126.

[1353] *See TAPS,* 225 F.3d at 687–88 *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 67 (citing *Interstate Nat. Gas Ass'n of Am.* v. *FERC,* 285 F.3d at 37).

[1354] *Id.* PP 1100–05.

[1355] *See, e.g., id.* P 1101 (citing *See* ACORE ANOPR Comments at 12; D.C. 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 Improvements to Generator Interconnection Procs. & Agreements,* Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at 41, *order on reh'g,* Order No. 2023–A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199, at P 14 (2024).

[1356] *Id.* (citing 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-aNew-Generator-Interconnection-Policy-1.pdf* (ACEG 2021 Interconnection Report) at 17.

[1357] *See id.* P 1147.

[1358] *Id.* P 1148.

[1359] *Id.* P 1149.

[1360] *Id.* P 1103.

interconnection process by meeting four qualifying criteria. Specifically, the Commission required transmission providers to evaluate 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.[1361]

526. The Commission found it necessary to establish these criteria to limit the scope of the requirement 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.[1362] The Commission found that these criteria strike a reasonable balance between precision and workability, and that each of the four criteria is necessary to identify the appropriate set of interconnection-related transmission needs.[1363] The Commission further found that the purpose of the criteria established in Order No. 1920 is 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.[1364]

527. As relevant here, the Commission proposed in the NOPR that part of the criteria regarding interconnection-related transmission needs is met where an interconnection-related network upgrade identified to meet interconnection-related transmission needs in the generator interconnection process has a voltage of at least 200 kV and/or an estimated cost of at least $30 million.[1365] In Order No. 1920, the Commission found it necessary and just and reasonable to modify the NOPR proposal such that any interconnection-related network upgrade identified to meet that interconnection-related transmission need must have a voltage of at least 200 kV *and* an estimated cost of at least $30 million (the cost-and-voltage criterion).[1366] The Commission found it necessary to establish a cost threshold that is stringent enough to capture those interconnection-related network upgrades that are likely to have caused the underlying interconnection requests to withdraw and a voltage threshold that is high enough 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.[1367] The Commission provided additional support for the voltage threshold in stating that 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.[1368]

528. The Commission stated that requiring an interconnection-related network upgrade identified to meet an interconnection-related transmission need to satisfy both the cost and voltage criteria will prevent transmission providers from evaluating interconnection-related transmission needs associated with interconnection-related network upgrades that are less likely to provide more widespread benefits to transmission customers.[1369] The Commission found that requiring both the cost threshold and the voltage threshold be met better limits the scope of the reform compared to the NOPR proposal and thus the reform is more likely to produce a smaller and more practicable set of interconnection-related needs that transmission providers must evaluate in their existing Order No. 1000 regional transmission planning processes.[1370] The Commission also stated that the change to require that both the cost threshold and the voltage threshold be met addresses commenters' concerns that relying on only one threshold would identify interconnection-related network upgrades that are less likely to provide more widespread benefits to transmission customers.[1371]

529. In Order No. 1920, the Commission also established as another qualifying criterion that transmission providers must have identified interconnection-related network upgrades in interconnection studies to address the same interconnection-related transmission need in at least two interconnection queue cycles during the preceding five years (repeat identification criterion).[1372] Like for the cost-and-voltage criterion, the Commission stated that the repeat identification criterion provides an important limit on the extent to which evaluation of regional transmission facilities to address interconnection-related transmission needs is required.[1373] The Commission further explained that repeat identification 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 and that the interconnection-related transmission need is likely to persist.[1374] The Commission explained that, if it did not limit the requirements in this way, the burden of evaluation would be greater because transmission providers could have to evaluate more interconnection-related transmission needs.[1375]

530. The Commission also clarified the timing of the requirement that transmission providers have 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.[1376] The Commission explained that this five-year period means looking back from the effective date of the Commission-

[1361] *Id.* P 1145.

[1362] *Id.* P 1146.

[1363] *Id.* PP 1146–1147.

[1364] *Id.* P 1150.

[1365] *Id.* P 1130.

[1366] *Id.* PP 1145, 1150–1151.

[1367] *Id.* P 1151.

[1368] *Id.* P 1146, n. 2433.

[1369] *Id.* P 1152.

[1370] *Id.* P 1146; *id.* P 1151; *id.* P 1153.

[1371] *Id.* P 1153 (citing Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; US DOE Initial Comments at 28.).

[1372] *Id.* P 1145.

[1373] *Id.* P 1150.

[1374] *Id.* PP 1150, 1158.

[1375] *Id.* P 1150.

[1376] *Id.* PP 1145, 1158–1160.

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.[1377] Separately, the Commission explained that 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).[1378] The Commission also clarified 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 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.[1379] Finally, the Commission stated that evaluation for selection of regional transmission facilities that address certain (*i.e.,* that qualify under the criteria established in Order No. 1920) 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.[1380]

531. For both the cost-and-voltage criterion and the repeat identification criterion, the Commission disagreed with commenters that argued for the adoption of different criteria or for the elimination of one or both criteria and found that requiring both criteria is just and reasonable.[1381]

2. Requests for Rehearing and Clarification

532. Clean Energy Associations contend that the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making by adopting the cost-and-voltage criterion and repeat identification criterion.[1382] Clean Energy Associations ask that the Commission, at a minimum, only require either a voltage criterion *or* cost criterion, such that the eligibility threshold is met if an interconnection-related network upgrade has a voltage of at least 200 kV *or* an estimated cost of at least $30 million.[1383] Clean Energy Associations also request that the Commission grant rehearing to change the repeat identification criterion, such that the criterion is met if an interconnection-related network upgrade was identified in at least one interconnection queue cycle.[1384] Separately, Clean Energy Associations ask the Commission to clarify that the time period transmission providers must use to identify interconnection-related network upgrades for inclusion in the initial regional transmission planning cycle exceeds five years, or alternatively, grant rehearing to require so.[1385]

533. As to the cost-and-voltage criterion, Clean Energy Associations contend that the Commission acted arbitrarily and capriciously because it failed to explain how interconnection-related network upgrades that satisfy both the voltage threshold and cost threshold (as required in Order No. 1920) are more likely to provide widespread benefits to customers compared to interconnection-related network upgrades that meet only the voltage threshold or only the cost threshold (as proposed in the NOPR).[1386] Clean Energy Associations claim that the Commission ignored record evidence and adopted eligibility criteria that arbitrarily exclude lower voltage facilities that cost more than $30 million from consideration in regional transmission planning processes regardless of the degree to which those interconnection-related network upgrades benefit transmission customers.[1387] Clean Energy Associations assert that the Commission ignored evidence that requiring both the cost threshold and the voltage threshold to be met is even more harmful in certain parts of the country.[1388]

534. Clean Energy Associations also claim that the Commission mischaracterized certain comments opposing the imposition of a requirement to meet both the cost threshold and the voltage threshold as comments favoring ''elimination of one or both criteria'' when many of such comments actually support what Clean Energy Associations refer to as the ''flexibility'' in the NOPR that only required an interconnection-related network upgrade to satisfy one of the thresholds to be eligible for evaluation.[1389] Clean Energy Associations further argue that the record shows that the NOPR's ''flexibility'' is more likely to identify interconnection-related transmission needs that warrant evaluation compared to the requirements in Order No. 1920, because Order No. 1920's requirement to meet both the cost threshold and the voltage threshold unduly limits the universe of transmission solutions in a manner that jeopardizes transmission providers' ability to evaluate transmission solutions that might be more efficient or cost-effective than other options.[1390] Clean Energy Associations claim that the Commission did not directly address the record evidence and arguments on this issue, which renders this aspect of the Order No. 1920 arbitrary and capricious.[1391]

535. On the repeat identification criterion, Clean Energy Associations contend that this criterion is arbitrary and inconsistent with Order No. 1920's goal of removing barriers to entry, increasing competition, and promoting more efficient or cost-effective solutions to interconnection-related transmission needs.[1392] Clean Energy Associations believe that the repeat identification criterion will render Order No. 1920's reforms to coordinate the regional transmission planning and generator interconnection processes ineffective for several reasons that the Commission failed to address, including the Commission's shift to cluster-based studies, the self-defeating nature of the repeat identification criterion, and the adverse effects of the repeat identification criterion in conjunction with the cost-and-voltage criterion.[1393] Clean Energy Associations claim that the Commission also ignored substantial record evidence and arguments relevant to the eligibility criteria and that the Commission's stated rationale for

[1377] *Id.* P 1145.

[1378] *Id.* P 1159.

[1379] We note that this accommodation will eventually become moot because transmission provides that do not already do so must transition to a cluster study rather than a serial process pursuant to the requirements of Order No. 2023. *See* Order No. 2023, 184 FERC ¶ 61,054 at P 223.

[1380] Order No. 1920, 187 FERC ¶ 61,068 at P 1159.

[1381] *Id.* P 1150 (citations omitted).

[1382] Clean Energy Associations Rehearing Request at 13–22.

[1383] *Id.* at 21–22.

[1384] *Id.*

[1385] *Id.* at 22–26.

[1386] *Id.* at 13–14.

[1387] *Id.* at 15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1137 (referencing comments of Pattern Energy, Pine Gate, and Shell)).

[1388] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1140 (referencing comments of PJM)).

[1389] *Id.* at 16 (citing Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32; Interwest Initial Comments at 3, 11).

[1390] *Id.* at 16–17.

[1391] *Id.* at 17.

[1392] *Id.* at 18.

[1393] *Id.* at 18–21.

adopting its unduly restrictive criteria "does not hold water." [1394]

536. Clean Energy Associations also request clarification on two issues related to the time period for the repeat identification criterion. First, Clean Energy Associations request that the Commission clarify that, for each transmission provider's initial regional transmission planning cycle under an Order No. 1920-compliant tariff, the review window for identifying interconnection-related network upgrades that are required to be considered as interconnection-related transmission needs may span more than five years in duration.[1395] As an example, Clean Energy Associations state that:

> if a transmission provider's Order No. 1920-compliant tariff takes effect on August 1, 2025, [and] the first regional transmission planning cycle in which interconnection-related transmission needs must be considered commences on August 1, 2027, and the date on which the transmission provider will identify the transmission solutions to be evaluated in that planning cycle is April 1, 2028, then the transmission provider must include for evaluation any network upgrades that were identified in interconnection cycles between August 1, 2020 (*i.e.,* five years before the effective date) and April 1, 2028 (*i.e.,* the date on which transmission solutions are identified for inclusion in the transmission planning process) and that meet the eligibility criteria. In that hypothetical example, the total time-period over which network upgrades could be identified for evaluation as interconnection-related transmission needs is seven years and nine months.[1396]

537. Second, noting the requirement in Order No. 1920, Clean Energy Associations request that the Commission clarify that any eligible interconnection-related network upgrade that is identified in any two interconnection cycles within the review window—even if both occurrences took place in the five years prior to the effective date—must be evaluated in the transmission providers' initial Order No. 1000 regional transmission planning cycle following the effective date of its Order No. 1920 compliance filing.[1397] Clean Energy Associations argue that there is no reason why the "later in time withdrawn interconnection request" must occur after the "effective date of the Commission-accepted tariff provisions" rather than at any point during the relevant lookback period. Clean Energy Associations claim that, absent the requested clarification, the Commission acted arbitrarily and capriciously and failed to engage in reasoned decision-making by failing to clearly identify the time period at which transmission providers must look to implement this reform.[1398]

3. Commission Determination

538. We disagree with Clean Energy Associations' requests for rehearing and decline to revise the cost-and-voltage criterion and the repeat identification criterion. We continue to find that it is necessary to limit the scope of the requirement 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.[1399] We reiterate the Commission's stated purpose of this reform, which is to address the narrow issue of interconnection-related transmission needs being repeatedly identified yet continuing to go unresolved through the generator interconnection process, even though more efficient or cost-effective regional transmission solutions could be achieved if such needs were evaluated through the regional transmission planning and cost allocation process.[1400]

539. We disagree with Clean Energy Associations' argument that the Commission acted arbitrarily and capriciously in adopting the requirement to meet both the cost threshold and the voltage threshold. In Order No. 1920, the Commission explained how the cost threshold is intended to capture interconnection-related network upgrades that cause underlying interconnection requests to withdraw (*i.e.,* are likely to persist), and the voltage threshold is intended to capture interconnection-related transmission needs that are likely to produce more widespread benefits.[1401] These explanations for requiring that previously identified interconnection-related network upgrades meet both of these thresholds for an interconnection-related transmission need to satisfy the cost-and-voltage criterion are consistent with the Commission's stated purpose and the necessary scope of this reform. Namely, the cost threshold identifies interconnection-related transmission needs associated with prohibitive interconnection-related network upgrade costs that contribute to a barrier to accessing the transmission system, and the voltage threshold identifies interconnection-related transmission needs with the potential for transmission benefits that extend beyond the interconnection customer.[1402] We also disagree with Clean Energy Associations' claim that the Commission ignored record evidence on this issue.[1403] As stated above, the Commission adopted this reform and the associated qualifying criteria to address a narrow issue with limited scope, not to address an expansive set of interconnection-related transmission needs as requested by some commenters in response to the NOPR.

540. We disagree with Clean Energy Associations that providing for the "flexibility" of meeting either the cost threshold or the voltage threshold is more consistent with Order No. 1920's objectives. Allowing such flexibility places Clean Energy Associations' preferred policy outcome in place of the need for reform articulated by the Commission.[1404] The Commission in Order No. 1920 explained that the coordination reform is not intended to create an expansive set of interconnection-related transmission needs that transmission providers must evaluate in the regional transmission planning and cost allocation processes. Instead, this reform is intended to identify a limited set of 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 believe that requiring transmission providers to consider a more limited set of interconnection-related transmission needs through their existing regional transmission planning and cost allocation processes is warranted

[1394] *Id.* at 20–21 (quoting *e.g.,* Interwest Initial Comments at 11 ("the NOPR imposes so many procedural hurdles that . . . it could not be expected to produce results . . . requiring that the same interconnection upgrades be identified twice . . . is simply impractical")).

[1395] *Id.* at 23–24.

[1396] *Id.* at 24.

[1397] *Id.* at 25 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1145 (establishing the requirement that the time period is "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)")).

[1398] *Id.* at 3, 25.

[1399] Order No. 1920, 187 FERC ¶ 61,068 at P 1146.

[1400] *Id.* P 1112.

[1401] *Id.* P 1151.

[1402] *Id.* PP 1103–1104.

[1403] Clean Energy Associations Rehearing Request at 15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1137 (referencing comments of Pattern Energy, Pine Gate, and Shell); Order No. 1920, 187 FERC ¶ 61,068 at P 1140 (referencing comments of PJM)).

[1404] Order No. 1920, 187 FERC ¶ 61,068 at PP 1106–1121.

because a more expansive set could include transmission needs associated with expensive but relatively low voltage interconnection-related network upgrades (which are less likely to provide widespread benefits to transmission customers compared to higher voltage transmission facilities) and transmission needs associated with high voltage but relatively inexpensive network upgrades (which are less likely to remain unbuilt by interconnection customers).

541. As explained in Order No. 1920, in the context of the repeat identification criterion, we are also concerned that relaxing the qualifying criteria would create greater burdens on transmission providers by increasing the number of interconnection-related transmission needs that transmission providers must evaluate in their Order No. 1000 regional transmission planning and cost allocation processes without widespread benefits to transmission customers.[1405] Additionally, the repeat identification criterion is meant to refine the evaluation to apply to more actionable and valuable interconnection-related transmission needs that may be better suited for evaluation and development in the existing Order No. 1000 regional transmission planning and cost allocation processes.

542. We disagree with Clean Energy Associations' claim that the requirement to meet both the cost threshold and the voltage threshold unduly limits the universe of transmission solutions in a manner that jeopardizes transmission providers' ability to evaluate transmission solutions that might be more efficient or cost-effective than other options. Clean Energy Associations conflate transmission needs and transmission solutions to address those needs. The purpose of the qualifying criteria adopted in Order No. 1920 is to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration.[1406] Contrary to Clean Energy Associations' claim, the qualifying criteria in Order No. 1920 do not limit the transmission solutions that transmission providers may evaluate to address the identified interconnection-related transmission needs. Instead, the qualifying criteria in Order No. 1920 limit the set of interconnection-related transmission needs that transmission providers must evaluate. We believe requiring transmission providers to evaluate this subset of transmission needs is justified because interconnection-related transmission needs that satisfy both the cost threshold and the voltage threshold can be solved with transmission facilities that are more likely to provide widespread benefits to the transmission system and be selected in the regional transmission for purposes of cost allocation as the more efficient and cost-effective transmission solution, compared to interconnection-related transmission needs that satisfy only the cost threshold, or only the voltage threshold.

543. We also disagree with Clean Energy Associations' claim that the Commission's decision to adopt the repeat identification criterion is arbitrary and inconsistent with the goals of Order No 1920. Clean Energy Associations' request for rehearing effectively asks the Commission to eliminate the repeat identification criterion to require the evaluation of more interconnection-related transmission needs in regional transmission planning processes, an argument that some commenters made in response to the NOPR and with which the Commission disagreed in Order No. 1920.[1407] The Commission explained in Order No. 1920 that the purpose of this criterion is to indicate that an interconnection-related transmission need is likely to persist and to limit the extent to which evaluation of regional transmission facilities to address interconnection-related transmission needs is required.[1408]

544. In response to Clean Energy Associations' request to clarify the timing requirements, and as more fully described below, we clarify that the time period that transmission providers use to identify interconnection-related transmission needs for potential consideration during any Order No. 1000 regional transmission planning and cost allocation process cycle will be longer than five calendar years. Additionally, we modify the requirements adopted in Order No. 1920 to resolve ambiguity about timing. We find that these modifications are necessary for transmission providers to determine precisely when the coordination requirements are triggered. Specifically, we modify criterion (1), the repeat identification criterion, and criterion (3), which specifies the maximum time period between withdrawals of interconnection requests associated with the same interconnection-related transmission need (the double withdrawal criterion). We also adopt a new criterion (5), which specifies the timing for identifying withdrawn interconnection requests associated with the same interconnection-related transmission need in the initial and successive Order No. 1000 regional transmission planning and cost allocation cycles (the withdrawal window criterion). The withdrawal window criterion clarifies the intent of the repeat identification criterion in Order No. 1920.[1409]

545. In particular, we modify the repeat identification criterion to read (with additions in bold and italicized and deletions struck through):

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[1405] *Id.* P 1150.

[1406] *Id.*

[1407] *Id.*

[1408] *Id.* PP 1150, 1158.

[1409] We also make a minor modification to criterion (4) to account for the fact that we are adopting an additional qualifying criterion. All the revisions detailed below are reflected in the Attachment K Appendix to this order.

> (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 ***(or in at least two individual interconnection studies for Transmission Providers that use a first-come, first-served serial generator interconnection process)***~~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)~~;

We also modify the double withdrawal criterion in Attachment K to read (with additions in bold and italicized and deletions struck through):

> (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 ***in two or more interconnection queue cycles (or two individual interconnection studies if the Transmission Provider uses a first-come, first-served serial generator interconnection process) have*** ~~has~~ been withdrawn ***and no more than five calendar years have passed between the date of an earlier interconnection request withdrawal and the date of a later interconnection request withdrawal***; ~~and~~

We make a slight modification to criterion (4) so that it reads (with additions in bold and italicized and deletions struck through):

> 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~~.~~***; and***

We also add a new criterion (5), the withdrawal window criterion, as follows (with additions in bold and italicized):

(5) The interconnection request withdrawals associated with the repeatedly identified interconnection-related transmission need occurred no earlier than seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. The initial evaluation should occur in the first Order No. 1000 regional transmission planning and cost allocation cycle to occur after the effective date of the tariff revisions implementing this reform. The transmission provider need not evaluate an interconnection-related transmission need that has been evaluated in a previous Order No. 1000 regional transmission planning and cost allocation cycle.

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546. We make these modifications to resolve confusion about the timing requirements for this reform. The Commission's *pro forma* generator interconnection procedures require an annual cluster request window for interconnection customers to submit interconnection requests.[1410] Over the span of the interconnection cycle, the transmission provider studies the interconnection requests and provides more refined interconnection study results.[1411] The requirements of this reform provide an opportunity for transmission providers to evaluate interconnection-related transmission needs associated with repeatedly identified interconnection-related network upgrades that are not developed through the generator interconnection process because the interconnection requests associated with interconnection-related network upgrade withdraw from the interconnection queue.[1412]

547. The modifications that we make here clarify that a transmission provider need not evaluate an interconnection-related transmission need if more than five calendar years separate the withdrawal of the earlier and later interconnection requests associated with an interconnection-related transmission need (the double withdrawal criterion). Additionally, the withdrawal window criterion makes clear that a transmission provider need only evaluate an interconnection-related transmission need in its Order No. 1000 regional transmission planning and cost allocation cycle if the withdrawal of the interconnection requests associated with the repeatedly identified interconnection-related transmission need occurred within the seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle.

548. We find that seven years is an appropriate period because it accounts for the time between withdrawn interconnection requests associated with otherwise eligible interconnection-related transmission needs (at most five years, as specified in the double withdrawal criterion) and accounts for the fact that the timing of generator interconnection queue cluster cycles likely does not coincide with the Order No. 1000 regional transmission planning and cost allocation cycle. Additionally, this seven-year period also accounts for the potential lag between the effective date of the Commission-approved tariff revisions and the initial Order No. 1000 regional transmission planning and cost allocation cycle (for the initial Order No. 1000 cycle) or the time between Order No. 1000 cycles (for subsequent Order No. 1000 cycles). Consequently, by establishing a seven-year withdrawal window period, we avoid the possibility of otherwise qualifying interconnection-related transmission needs being ineligible for evaluation in an Order No. 1000 regional transmission planning and cost allocation cycle due to an inadequate withdrawal window period that does not account for lags between processes.

549. We also believe this seven-year period for the withdrawal window is simpler to calculate than the language that the Commission previously adopted for the repeat identification criterion in Order No. 1920 (before the modifications described here). The reason is that transmission providers will only need to look back seven calendar years from a single date (the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle). Without the modifications adopted here, the first qualifying criterion of the repeat identification criterion in Order No. 1920 established several look-back periods in reference to multiple dates.[1413]

550. As a result of the modifications above, there is no need to distinguish between the initial Order No. 1000 regional transmission planning and cost allocation cycle and subsequent No. 1000 regional transmission planning and cost allocation cycles. Thus, for the initial implementation of this reform, the transmission provider need only determine if the qualifying criteria are satisfied for the period beginning seven calendar years before the initial Order No. 1000 regional transmission planning and cost allocation cycle commencement date. We acknowledge

[1410] *See pro forma* LGIP § 3.4.1. As Order No. 1920 recognizes, however, for a transmission provider that operates a serial process and studies interconnection requests on a first-come, first served basis, the criterion will be met 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. Order No. 1920, 187 FERC ¶ 61,068 at P 1160. As noted above, however, this intricacy will be rendered moot as transmission providers with serial queues come into compliance with Order No. 2023, which requires them to transition to a cluster study process. *Supra* P 530 n.1380; *see* Order No. 2023, 184 FERC ¶ 61,054 at P 223.

[1411] *See, e.g., pro forma* §§ LGIP 3.1.1 (Study Deposits), 7 (Cluster Study), 8 (Interconnection Facilities Study), 9 (Affected Systems Study), 10 (Option Interconnection Study).

[1412] Order No. 1920, 187 FERC ¶ 61,068 at P 1108 (because "the high cost of interconnection is increasing the rate at which generators withdraw from the interconnection queue. . . . interconnection customers are unlikely to resolve these interconnection-related transmission needs through the generator interconnection process.")

[1413] *Id.* P 1145 ("(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)").

that, in implementation, this start date is likely to be earlier than the start date established in Order No. 1920.[1414] As a result, transmission providers may need to consider one or two additional years of withdrawn interconnection requests during the initial Order No. 1000 regional transmission planning and cost allocation cycle. However, we believe this departure from Order No. 1920 is necessary to resolve the ambiguity raised on rehearing and to establish clear qualifying criteria for transmission providers to implement going forward.

551. In addition, the withdrawal window criterion makes clear that a transmission provider need not evaluate an interconnection-related need that meets all the qualifying criteria if it has already evaluated that interconnection-related transmission need in an Order No. 1000 regional transmission planning and cost allocation cycle. This modification is necessary to prevent transmission providers from having to evaluate an interconnection-related transmission need in more than one Order No. 1000 regional transmission planning and cost allocation cycle.

552. Consistent with the adoption of the withdrawal window criterion, we clarify for Clean Energy Associations that the time period that transmission providers use to identify interconnection withdrawals is longer than five calendar years. In particular, the withdrawal window criterion requires the transmission provider to determine if the interconnection request withdrawals associated with the repeatedly identified interconnection-related transmission need occur within seven calendar years prior to the commencement of the relevant Order No. 1000 regional transmission planning and cost allocation cycle.

553. To explain how this would work, consider the following hypothetical and assume that the voltage-and-cost threshold criterion is satisfied:

- Transmission provider identifies interconnection-related transmission need A as necessary to interconnect interconnection request A in interconnection cluster cycle 1.
- Interconnection request A withdraws from interconnection cluster cycle 1 on August 1, 2035.
- In interconnection cluster cycle 2, transmission provider identifies interconnection-related transmission need A as necessary to interconnect interconnection request B.
- Interconnection request B withdraws from interconnection cluster cycle 2 on or before August 1, 2040.
- The first Order No. 1000 regional transmission planning and cost allocation cycle following the withdrawal of interconnection request B commences on January 1, 2042.

In this example, the repeat identification criterion would be satisfied because the same interconnection-related transmission need was identified for interconnection request A and interconnection request B in interconnection cluster cycle 1 and interconnection cluster cycle 2, respectively. The double withdrawal criterion would be satisfied because no more than five calendar years have passed between the withdrawal of interconnection request A and interconnection request B. The withdrawal window criterion would be satisfied because the withdrawals of interconnection request A and interconnection request B occurred within seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. Consequently, the transmission provider would be required to evaluate interconnection-related transmission need A in the Order No. 1000 regional transmission planning and cost allocation cycle that commences on January 1, 2042.

554. We turn now back to Clean Energy Associations' first clarification request and explain these requirements using the dates provided in Clean Energy Associations' example, where the relevant tariff revisions would become effective August 1, 2025, the initial Order No. 1000 regional transmission planning and cost allocation cycle would commence on August 1, 2027, and the transmission solutions to be evaluated will be identified on April 1, 2028.

555. We clarify that the April 1, 2028 date would not be relevant for determining whether a transmission provider must evaluate an interconnection-related transmission need. The relevant dates are the interconnection request withdrawal dates and the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. In Clean Energy Associations' example, the transmission provider would identify interconnection request withdrawals between August 1, 2020 (seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle provided in this example) and August 1, 2027 (the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle provided in this example). Of those withdrawals, the repeat identification criterion will be satisfied if no more than five calendar years elapsed between the earlier and later interconnection request withdrawal dates for interconnection requests associated with the same repeatedly identified interconnection-related transmission need. Thus, withdrawals of interconnection requests with the earlier occurring on August 1, 2020 and the later occurring August 1, 2025 would satisfy the double withdrawal criterion. The same is true for withdrawals of interconnection requests with the earlier occurring on August 1, 2022 and the later occurring August 1, 2027. The double withdrawal criterion would not be satisfied, however, if the first withdrawal occurred on August 1, 2020 and the later occurred on August 2, 2025 because more than five calendar years occur between the earlier and later interconnection request withdrawals.

556. Additionally, in response to Clean Energy Associations' second request for clarification, we note that the modifications to the repeat identification criterion adopted here delete the Attachment K language adopted in Order No. 1920 that created confusion.[1415] Consistent with the modifications adopted here, we clarify that the double withdrawal criterion requires that no more than five calendar years occur between the earlier and later interconnection request withdrawals and that the withdrawal window criterion makes clear that transmission providers need not evaluate an interconnection-related transmission need if the relevant interconnection request withdrawals do not occur within the seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle.

C. Cost Allocation

1. Order No. 1920 Requirements

557. In Order No. 1920, the Commission adopted new coordination requirements to require that transmission providers 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.[1416] The Commission also stated that requests to modify existing cost allocation criteria were outside the scope of the proceeding.[1417] Additionally, the

[1414] *Id.* P 1159.

[1415] *See id.* P 1145.

[1416] *Id.* P 1111.

[1417] *Id.* P 1112.

Commission stated that 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. Further, Order No. 1920 did not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process.[1418] The Commission went on to explain that, to the extent that transmission providers wish to propose changes to their Order No. 1000 regional cost allocation method(s) because of this new requirement, they would need to do so in separate FPA section 205 filings rather than on compliance with Order No. 1920.[1419]

2. Requests for Rehearing and Clarification

558. Retail Regulators, Ohio Consumers, NRECA, Undersigned States, and West Virginia Commission argue that Order No. 1920's coordination reform shifts the costs of generator interconnection to load.[1420] In particular, Retail Regulators and Undersigned States argue that this requirement is another means to transfer network upgrade costs necessitated by generator interconnection to load and they contend, along with West Virginia Commission, that shifting these costs is not just and reasonable.[1421] Undersigned States further argue that this shift violates the FPA, and that Order No. 1920's failure to account for these effects is arbitrary and capricious.[1422] Relatedly, PJM argues that this reform is arbitrary and capricious because it reopens accepted cost allocation methods in Order Nos. 1000 and 2023 that were built on the premise that the cost causer pays for the interconnection costs.[1423]

559. NRECA states that the Commission has failed to consider that its policies governing interconnection-related network upgrades—particularly allowing participant funding in RTOs/ISOs—are intended to result in a just and reasonable allocation of the costs of interconnection-related network upgrades.[1424] Industrial Customers argue that Order No. 1920 abruptly abandons participant funding, which it characterizes as a ''longstanding'' model that sends proper pricing signals for generation developers to select projects close to load while also protecting existing transmission customers from subsidizing interconnection of new generation.[1425] East Kentucky argues that the Commission:

> has not provided a reasonable explanation of how this requirement does not result in unjust, unreasonable, and unduly discriminatory transmission rates in violation of Section 206 of the Federal Power Act, 16 U.S.C. 824e, and does not alter, without adequate explanation or evidence, the Commission's existing interconnection pricing and participant funding polices.[1426]

560. Industrial Customers state that the Commission ignored arguments that the Commission must rationally explain its decision to depart from the existing just and reasonable ''but for'' policy of Order No. 2003.[1427] Industrial Customers argue that the Commission should not justify its ''cost allocation techniques by arguing that interconnection costs for renewable energy resources are too high and should be socialized across all transmission customers.'' [1428] Industrial Customers further argue that Order No. 1920 changes prior Commission policies without setting forth a reasonable and adequate explanation for resulting shifting of costs.[1429]

561. Ohio Consumers argue that Order No. 1920 is inconsistent with Order No. 2003 incentives because it shifts network upgrade costs that would have incentivized generation developers to locate in ''the right area.'' [1430] NRECA argues that requiring evaluation and selection of unbuilt interconnection-related network upgrades in the existing Order No. 1000 regional transmission planning and cost allocation processes gives an undue preferential treatment to generation developers, a group that would ordinarily fund the network upgrades in the first instance.[1431] Further, NRECA states that the Commission has made no finding that the Commission's policies allowing participant funding in RTOs/ISOs for interconnection-related network upgrades have become unjust and unreasonable and should be replaced.[1432]

3. Commission Determination

562. We sustain Order No. 1920 and find that the coordination requirements in Order No. 1920 do not require changes to existing cost allocation methods that transmission providers have adopted in either the generator interconnection or existing Order No. 1000 regional transmission planning and cost allocation processes. Therefore, those existing cost allocation methods adopted by transmission providers remain intact.

563. To this point, in response to Retail Regulators, Ohio Consumers, NRECA, Undersigned States, West Virginia Commission, and PJM, we first note that the coordination reform does not alter existing cost allocation methods or create a new cost allocation method for generator interconnection processes. Rather, the purpose of the coordination reform is to require transmission providers to *evaluate,* in the existing Order No. 1000 regional transmission planning and cost allocation processes, certain (*i.e.,* that qualify under the criteria established in Order No. 1920) interconnection-related transmission needs that were not addressed through the generator interconnection process because the identified interconnection-related network upgrades were never constructed pursuant to that process. If an interconnection customer enters into a generator interconnection agreement, the transmission provider will construct the identified interconnection-related network upgrades and allocate their costs in accordance with the transmission provider's Commission-accepted cost allocation approach for such interconnection-related network upgrades. If an interconnection customer does not enter into a generator interconnection agreement for its interconnection request, however, the identified interconnection-related network upgrades will not be constructed pursuant to the generator interconnection process; thus, the generator interconnection cost allocation approach would not apply.

564. Moreover, in response to NRECA and PJM, the coordination reform does

[1418] *Id.* P 1117.

[1419] *Id.* P 1118.

[1420] Retail Regulators Rehearing Request at 43–44; Ohio Consumers Rehearing Request at 8; NRECA Rehearing Request at 45; Undersigned States Rehearing Request at 37; West Virginia Commission Rehearing Request at 16.

[1421] Retail Regulators Rehearing Request at 43–44; Undersigned States Rehearing Request at 37; West Virginia Commission Rehearing Request at 16.

[1422] Undersigned States at 37.

[1423] PJM Rehearing Request at 36 (citing *Midwest ISO Transmission Owners,* 373 F.3d at 1368 (citing 5 U.S.C. 706(2)(A)); *State Farm,* 463 U.S. at 43; *Wis. Gas Co.* v. *FERC,* 770 F.2d at 1156; *see also* Industrial Consumers Rehearing Request at 48.

[1424] NRECA Rehearing Request at 48.

[1425] Industrial Customers Rehearing Request at 41.

[1426] East Kentucky Rehearing Request at 3.

[1427] Industrial Customer Rehearing Request at 41.

[1428] *Id.* at 43.

[1429] *Id.* at 45.

[1430] Ohio Consumers Rehearing Request at 8–9; *see also* Industrial Consumers Rehearing Request at 42.

[1431] NRECA Rehearing Request at 46.

[1432] *Id.* at 48.

not create a new regional cost allocation method for the existing Order No. 1000 regional transmission planning and cost allocation processes. Instead, transmission providers must now, pursuant to this reform, *evaluate* certain interconnection-related transmission needs pursuant to their existing Order No. 1000 regional transmission planning and cost allocation processes. The transmission provider may adopt the evaluation method and selection criteria from any of its existing Order No. 1000 regional transmission planning and cost allocation processes (*e.g.,* economic or reliability process) to evaluate and potentially select transmission facilities that address these transmission needs. To the extent that such a transmission facility is selected, it will have met the selection criteria for the applicable Order No. 1000 regional transmission planning process and be eligible for cost allocation pursuant to a regional cost allocation method that has been found to allocate costs of transmission facilities selected through that process in a manner that is at least roughly commensurate with benefits.

565. We reiterate, however, that there is no obligation for transmission providers to select a transmission facility that addresses the interconnection-related transmission need that must be evaluated pursuant to this reform.[1433] As the Commission stated in Order No. 1920, in order for the transmission facility associated with the relevant interconnection-related transmission need to be eligible for cost allocation pursuant to transmission providers' existing Order No. 1000 regional cost allocation method, the transmission provider ''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.'' [1434] The Commission also stated that ''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.'' [1435] The Commission explained that, to the extent that the coordination reform results in transmission providers selecting a transmission facility that, among other things, addresses an interconnection-related transmission need in the existing Order No. 1000 regional transmission planning and cost allocation processes, they would have done so because the selected transmission facility was evaluated and determined by the transmission provider to be eligible for selection in the regional transmission plan for purposes of cost allocation and is the more efficient or cost-effective regional transmission solution. Moreover, we reiterate that the reform adopted here does not compel transmission providers to adopt a new cost allocation method for transmission facilities that address interconnection-related transmission needs.

D. Gaming

1. Order No. 1920 Requirements

566. In Order No. 1920 the Commission did not adopt revisions to the proposed coordination reform in response to assertions that the reform would lead to ''gaming,'' resulting in spurious interconnection requests. The Commission explained that interconnection requests require significant financial commitments from interconnection customers, which the Commission made more stringent in Order No. 2023. Consequently, the Commission considered it unlikely that an interconnection customer would submit multiple interconnection requests in multiple interconnection queue cycles to trigger the requirement for transmission providers to evaluate, as part of their existing Order No. 1000 regional transmission planning and cost allocation processes, regional transmission facilities that may address certain interconnection-related transmission needs. The Commission noted that an interconnection customer would face various risks 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.[1436]

2. Requests for Rehearing and Clarification

567. PJM and NRECA argue that Order No. 1920 is arbitrary and capricious because it creates perverse incentives for generation developers to game the interconnection process and shift interconnection-related network upgrade costs in an unduly discriminatory manner onto transmission customers.[1437] PJM and NRECA argue that the evidence does not support the Commission's reasoning that the stringent financial commitments required in the interconnection process will prevent gaming.[1438]

568. PJM states that, in its generator interconnection process, an interconnection customer's initial readiness deposit is only at risk prior to the interconnection customer learning its assigned network upgrade cost responsibility.[1439] PJM further states that, for a hypothetical 300 MW project that would trigger the $30 million dollar threshold in the final rule,[1440] the interconnection customer would only risk its readiness deposit of $1.2 million prior to withdrawing and having to post an additional deposit.[1441] PJM asserts that a sophisticated developer can leverage that low risk and enhance its chances of selection for PJM's Regional Transmission Expansion Plan (RTEP) by submitting well-formed and strategically positioned, but specious, interconnection requests.[1442] PJM asserts that, as a result, such developers can flood the PJM interconnection process with speculative and larger than necessary interconnection requests and withdraw shortly after the required network upgrade costs are identified.[1443] PJM asserts that this would force it to reconsider RTEP upgrades that would incorporate the needed network upgrades and assign cost responsibility to load rather than to the generation developers.[1444]

569. PJM asserts that the final rule discounts these concerns despite PJM's demonstration that the risk-to-benefit ratio heavily favors the submission of speculative interconnection requests for a relatively low at-risk deposit. PJM argues that this risk-to-benefit ratio justifies the potential risk of non-selection in RTEP that a developer may face.[1445]

3. Commission Determination

570. We do not find persuasive arguments raised on rehearing and continue to find that no revisions to Order No. 1920's coordination requirement are necessary to address the speculative gaming concerns raised in this proceeding.[1446] With respect to PJM's specific generator interconnection

[1433] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1156.

[1434] *Id.* P 1117.

[1435] *Id.*

[1436] *Id.* P 1119.

[1437] PJM Rehearing Request at 33; NRECA Rehearing Request at 44, 46–47.

[1438] PJM Rehearing Request at 33; NRECA Rehearing Request at 46.

[1439] PJM Rehearing Request at 34.

[1440] Order No. 1920, 187 FERC ¶ 61,068 at P 1155.

[1441] PJM Rehearing Request at 35.

[1442] *Id.* at 36.

[1443] *Id.* at 35.

[1444] *Id.*

[1445] PJM Rehearing Request at 36.

[1446] Order No. 1920, 187 FERC ¶ 61,068 at P 1119.

process, we disagree with PJM that the risk an interconnection customer faces of losing only its readiness deposit if it withdraws is too low a risk to mitigate gaming concerns. Specifically, PJM's own hypothetical example demonstrates that an interconnection customer would risk losing $1.2 million for a single interconnection request, a risk that that we do not consider inconsequential. Moreover, for a single interconnection customer to attempt this gaming strategy, it would have to put its study and readiness deposits at risk in at least two interconnection queue cycles, and therefore would put at risk $2.4 million ($1.2 million per cycle) for the underlying interconnection-related transmission need to trigger the repeat identification criterion to qualify for evaluation in the Order No. 1000 regional transmission planning and cost allocation processes.[1447] Therefore, the risk is higher than what PJM asserts.

571. Additionally, we continue to find it unlikely that an interconnection customer would submit multiple interconnection requests (in multiple interconnection queue cycles) to trigger this requirement because the interconnection customer would face additional uncertainty in that transmission providers may not select a transmission facility that addresses the interconnection-related network upgrade in a regional transmission plan for purposes of cost allocation. We also reiterate that pursuing such a strategy would entail other risks, including the risk that any of the five qualifying criteria will not be met and the possibility that the newly created interconnection or transmission capacity will not benefit the interconnection customer that submitted, and withdrew, the interconnection requests in multiple interconnection queue cycles because the entity that withdrew the interconnection requests has no preferential claim to that capacity.[1448] For these reasons, we believe the financial risks and process-related restrictions make it unlikely that a generation developer would risk time and resources to ''game'' this process in the hope of benefiting from an uncertain process, which is highly unlikely to produce the generation developer's preferred result.

[1447] *Id.* PP 1119, 1145.

[1448] *See id.* P 1119.

E. Transmission Planning Process Evaluation

1. Order No. 1920 Requirements

572. In Order No. 1920, the Commission required 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, as was proposed in the NOPR. The Commission explained that by requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes, such needs will be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions.[1449]

573. The Commission agreed 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. The Commission disagreed with commenters that asserted that the Commission's coordination proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support generator interconnections. The Commission anticipated that as transmission providers gain experience with Long-Term Regional Transmission Planning they will identify 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.[1450]

[1449] *Id.* P 1126.

2. Requests for Rehearing and Clarification

574. NRECA and East Kentucky argue that the Commission did not provide sufficient notice and opportunity to comment on the final rule's requirement to evaluate for selection transmission facilities to address identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes rather than in Long Term-Regional Transmission Planning process, as the NOPR proposed.[1451]

575. Clean Energy Associations claim that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate network upgrades that address interconnection-related transmission needs in Long-Term Regional Transmission Planning.[1452] Clean Energy Associations argue that if one assumes that the Order No. 1920 rationale is true, *i.e.,* that the existing Order No. 1000 regional transmission planning and cost allocation processes are a faster and more effective means of getting these facilities built, then such rationale does not justify the Commission's failure to also require evaluation of those upgrades in Long-Term Regional Transmission Planning.[1453] Clean Energy Associations allege that Order No. 1920, by limiting the mandatory consideration of interconnection-related network upgrades to the existing Order No. 1000 regional transmission planning and cost allocation processes, will necessarily fail to require transmission providers to evaluate benefits of transmission facilities that would result from their selection. Clean Energy Associations allege that any transmission upgrade, including interconnection-related network upgrades, is more likely to be selected in the ''more robust'' Long-Term Regional Transmission Planning, which they believe is consistent with the Commission's justifications of the reform and supported by the record.[1454]

576. Clean Energy Associations assert that the Commission's expectation that fewer interconnection-related network upgrades would be identified over time, in part due to transmission providers' consideration of Factor Category Six (Generator Interconnection Requests

[1450] *Id.* P 1127.

[1451] East Kentucky Rehearing Request at 1–2; NRECA Rehearing Request at 15–16.

[1452] Clean Energy Associations Rehearing Request at 4–6.

[1453] *Id.* at 6.

[1454] *Id.* at 7.

and Withdrawals), is no grounds to deny a parallel path for transmission providers to evaluate interconnection-related transmission needs through Long-Term Regional Transmission Planning because the categories of factors apply to identifying Long-Term Transmission Needs, rather than evaluating specific facilities for possible selection.[1455] Clean Energy Associations claim that the Commission's requirement to evaluate interconnection-related transmission needs is more analogous to the evaluation requirements than to the Long-Term Scenarios requirements of Long-Term Regional Transmission Planning. Clean Energy Associations argue, therefore, that it is not just and reasonable, nor is it comparable, to assume that Factor Category Six is duplicative of evaluating interconnection-related network upgrades in Long-Term Regional Transmission Planning.

577. Clean Energy Associations further argue that evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning may serve as a needed fail-safe for addressing current interconnection-related transmission needs if a particular transmission provider's existing Order No. 1000 regional transmission planning and cost allocation processes prove to be ineffective for that purpose.[1456] Clean Energy Associations assert that to maximize the chances that more efficient or cost-effective projects will be successfully developed, the Commission should require transmission providers to evaluate qualifying interconnection-related network upgrades in both Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning and cost allocation processes.[1457]

578. Clean Energy Associations claim that the record demonstrates that interconnection-related network upgrades provide transmission benefits beyond the interconnection customers triggering them, and it is therefore reasonable to require their evaluation with comparable high-voltage, high-cost facilities in Long-Term Regional Transmission Planning.[1458] Clean Energy Associations also state that evaluation of interconnection-related network upgrades in Long-Term Regional Transmission Planning is the logical precedent for the voluntary funding option for interconnection customers because it will provide potential funders of the transmission facilities with a comparable way to evaluate the benefits of that facility.[1459]

579. Finally, Clean Energy Associations request that, at a minimum, the Commission clarify that Order No. 1920 does not prohibit transmission providers from evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning.[1460]

580. Large Public Power argues that by specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes, Order No. 1920 will dramatically skew the Order No. 1000 processes and is fundamentally at odds with the Commission's objective of not disrupting planning for reliability and economic needs put in place under Order No. 1000.[1461] Large Public Power also argues that specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes is inconsistent with the approach to developing Long-Term Scenarios, which ''call[s] for a holistic analysis which enables system planners to make informed, balanced decisions to address the unique Long-Term Transmission Needs of each planning region.'' [1462] Large Public Power asserts that the Commission failed to explain why generation interconnection application withdrawals should be the only consideration to determine transmission needs under existing Order No. 1000 regional transmission planning and cost allocation processes.[1463]

581. PJM claims that the withdrawn and speculative interconnection requests, as potential drivers of regional transmission needs, would insert an unjustified level of uncertainty into its existing Order No. 1000 regional transmission planning and cost allocation processes.[1464] PJM also asserts that the final rule is arbitrary and capricious because it requires consideration of withdrawn interconnection requests in its near-term RTEP and provides them undue preference over interconnection requests that have taken all required steps to obtain site control, permits, and regulatory approvals and have paid deposits.[1465] PJM contends that under the final rule, the output of the RTEP process, which is used in the generator interconnection process, ''would be inflated by the addition of questionable transmission upgrades.'' [1466] Thus, PJM claims, the RTEP and generator interconnection processes, which are meant to work in tandem, would become unnecessarily separated and infused with dubious inputs and drivers.[1467]

3. Commission Determination

582. We disagree with NRECA and East Kentucky that the Commission failed to provide adequate notice of and opportunity to comment on Order No. 1920's requirement that transmission providers in each transmission planning region evaluate for selection 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.[1468]

583. A final rule is a logical outgrowth of a proposed rule where ''a reasonable member of the regulated class'' could ''anticipate the general aspects of the [final] rule.'' [1469] Order No. 1920 satisfies this standard because the NOPR explicitly requested comment on how the proposed reform ''should interact with existing regional transmission planning processes and the Long-Term Regional Transmission Planning proposed herein,'' [1470] which put parties on notice that the Commission was contemplating the change that NRECA and East Kentucky now argue is not a logical outgrowth of the NOPR. Courts have explained that ''[n]otice suffices when [an agency] has 'expressly asked for comments on a particular issue or

[1455] *Id.* at 7–8.

[1456] *Id.* at 8.

[1457] *Id.* at 9.

[1458] *Id.* at 10–11.

[1459] *Id.* at 11–12.

[1460] *Id.* at 12–13.

[1461] Large Public Power Rehearing Request at 21.

[1462] *Id.* at 21–22.

[1463] Large Public Power Rehearing Request at 22.

[1464] PJM Rehearing Request at 37–38.

[1465] *Id.*

[1466] *Id.* at 38.

[1467] *Id.*

[1468] East Kentucky Rehearing Request at 1–2; NRECA Rehearing Request at 15–16.

[1469] *Telesat Canada* v. *FCC,* 999 F.3d at 713–14 (quotations omitted). We note that, while 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, we believe that evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning would also be appropriate. The inability to require that transmission providers consider regional transmission facilities to address interconnection-related transmission needs in Order No. 1000 processes would not have prevented the Commission from issuing Order No. 1920.

[1470] NOPR, 179 FERC ¶ 61,028 at P 174.

otherwise made clear that the agency was contemplating a particular change.' '' [1471] Here, by requesting comment on the issue, the Commission put parties on notice that it was continuing to contemplate how the proposed reform should interact with both proposed Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.

584. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a ''logical outgrowth'' of the proposed rule.[1472] The final rule is a logical outgrowth of the NOPR in this regard. In the NOPR, the Commission proposed to require that transmission providers evaluate for selection in the regional transmission plan for purposes of cost allocation regional transmission facilities to address certain interconnection-related needs that meet specific qualifying criteria established by the Commission.[1473] Order No. 1920 adopted this requirement and mandated that such consideration occur in existing Order No. 1000 regional transmission planning and cost allocation processes,[1474] rather than in Long-Term Regional Transmission Planning, as the NOPR proposed.[1475] The Commission explained that this change will allow interconnection-related transmission needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions. We find that this change satisfies the logical outgrowth test because while the Commission modified the type of regional transmission planning and cost allocation processes that would be subject to coordination with interconnection-related transmission needs, it retained the underlying requirement that such coordination occur. Thus, Order No. 1920's requirement ''follow[s] logically from'' the NOPR because the NOPR ''adequately frame[d] the subjects for discussion.'' [1476]

585. We are unpersuaded by Clean Energy Associations' assertion that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate network upgrades that address interconnection-related transmission needs in Long-Term Regional Transmission Planning. We continue to find that evaluating interconnection-related transmission needs associated with this coordination requirement is more appropriate in the existing Order No. 1000 regional transmission planning and cost allocation processes than in Long-Term Regional Transmission Planning because such evaluation would occur at shorter intervals and would be more likely to result in expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.[1477] We find that it is unnecessary to require transmission providers to also evaluate interconnection-related transmission needs associated with this coordination requirement in Long-Term Regional Transmission Planning because the coordination requirement in Order No. 1920 is just and reasonable and sufficient to address the need for reform.

586. In addition, we reiterate that transmission providers must consider future interconnection-related transmission needs as a driver of Long-Term Transmission Needs in Long-Term Regional Transmission Planning through the development of Long-Term Scenarios, which must incorporate generator interconnection withdrawals in Factor Category Six (Generator Interconnection Requests and Withdrawals).[1478] Factor Category Six allows transmission providers to consider a broader range of potential interconnection-related transmission needs compared to the interconnection-related transmission needs that meet the coordination requirement's qualifying criteria. Moreover, to the extent that an interconnection-related transmission need is not addressed according to this coordination requirement, transmission providers may choose to consider similar interconnection-related transmission needs as Long-Term Transmission Needs and evaluate Long-Term Regional Transmission Facilities to address those needs in Long-Term Regional Transmission Planning. Therefore, we believe that requiring transmission providers to evaluate interconnection-related transmission needs identified by this coordination requirement in Long-Term Regional Transmission Planning would be redundant to existing Order No. 1920 requirements and could inappropriately limit the scope of the interconnection-related transmission needs that transmission providers consider in Long-Term Regional Transmission Planning.

587. On this point, we disagree with Clean Energy Associations' claim that it is not just and reasonable, nor is it comparable, to assume Factor Category Six is duplicative of evaluating interconnection-related network upgrades in Long-Term Regional Transmission Planning, and that this coordination requirement is more analogous to the Long-Term Regional Transmission Planning evaluation requirements. Both the qualifying criteria of the coordination requirement and the categories of factors of the Long-Term Scenarios requirements (in Long-Term Regional Transmission Planning) establish how transmission providers identify transmission needs. We recognize that the coordination requirement mandates the evaluation of regional transmission facilities to address interconnection-related transmission needs associated with this coordination requirement, albeit allowing for flexibility in how transmission providers evaluate such facilities for selection, but Long-Term Regional Transmission Planning does not mandate evaluation of a specific type of transmission facility.[1479] However, the requirement to evaluate regional transmission facilities associated with the coordination requirement is similar to the Long-Term Regional Transmission Planning requirement for transmission providers to establish a 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 (which, as discussed above, will include future interconnection-related transmission needs). This explanation addresses Clean Energy Associations' concern that Order No. 1920 will necessarily fail to require transmission providers to evaluate benefits of transmission facilities to address interconnection-related transmission needs through Long-Term Regional Transmission Planning.

588. In response to Clean Energy Associations' request for clarification that Order No. 1920 does not prohibit transmission providers from evaluating

[1471] *Brennan* v. *Dickson,* 45 F.4th at 69 (quoting *CSX Transp., Inc.* v. *Surface Transp. Bd.,* 584 F.3d at 1081).

[1472] *Long Island Care,* 551 U.S. at 174–75; *see also Am. Paper Inst.* v. *EPA,* 660 F.2d at 959 n.13 (''An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.'' (emphasis added)).

[1473] NOPR, 179 FERC ¶ 61,028 at P 166.

[1474] Order No. 1920, 187 FERC ¶ 61,068 at P 1126.

[1475] NOPR, 179 FERC ¶ 61,028 at P 167.

[1476] *Conn. Light & Power Co.* v. *Nuclear Regulatory Comm'n,* 673 F.2d at 533.

[1477] Order No. 1920, 187 FERC ¶ 61,068 at P 1126.

[1478] *Id.* PP 1127–1128.

[1479] *Id.* P 1111.

interconnection-related transmission needs in Long-Term Regional Transmission Planning, we reiterate that future interconnection-related transmission needs must be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios.[1480] We clarify that Order No. 1920 does not prohibit transmission providers from proposing on compliance how they will identify and evaluate future interconnection-related transmission needs in Long-Term Regional Transmission Planning. However, we will not prejudge Clean Energy Associations' proposal for a ''parallel path'' for identifying and evaluating interconnection-related transmission needs in Long-Term Regional Transmission Planning using the coordination requirement's qualification criteria.[1481] If any transmission provider chooses to develop additional processes to address interconnection-related transmission needs in Long-Term Regional Transmission Planning, they must demonstrate that the proposal is consistent with or superior to Order No. 1920's requirements.

589. We are not persuaded by Large Public Power's argument that, in Order No. 1920, the Commission is specifying that interconnection applications and withdrawals are the sole criterion for project selection in existing Order No. 1000 regional transmission planning and cost allocation processes. To this point, we first note that Order No. 1920 adopts not one, but five, criteria for interconnection-related transmission needs to be evaluated through existing Order No. 1000 regional transmission planning and cost allocation processes. That is, evaluation is only required when the interconnection-related network upgrades driving interconnection-related transmission needs meets the five qualification criteria established in Order No. 1920.[1482]

590. Furthermore, the evaluation requirement only requires transmission providers to *evaluate* interconnection-related transmission needs in the Order No. 1000 regional transmission planning process. It does not require that transmission providers use interconnection-related transmission needs as a criterion to decide whether to select a regional transmission facility in the Order No. 1000 regional transmission planning process nor does it require that the interconnection-related transmission need be resolved. As the Commission explained, these requirements provide flexibility in how transmission providers evaluate transmission facilities for selection by allowing them to 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. The Commission thus permitted transmission providers to propose the best method to incorporate this new requirement for their transmission planning region and encouraged 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.[1483]

591. We also disagree with PJM's assertions that the Order No. 1920 requirement is arbitrary and capricious because the requirement would insert an unjustified level of uncertainty into its existing Order No. 1000 regional transmission planning and cost allocation processes by requiring consideration of withdrawn interconnection requests in its near-term RTEP. As explained here and in Order No. 1920, we are not requiring that transmission providers develop transmission facilities through the Order No. 1000 regional transmission planning and cost allocation processes as transmission solutions to address interconnection-related transmission needs. The coordination reform simply creates an avenue for evaluation of qualifying interconnection-related transmission needs in the existing Order No. 1000 regional transmission planning and cost allocation processes. Further, Order No. 1920 gives transmission providers flexibility to ''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'' [1484]

592. Additionally, we disagree with PJM that the Order No. 1920 requirement gives undue preference to withdrawn interconnection requests. Instead, the requirement addresses a barrier to entry for new generation resources, where repeated interconnection requests are increasingly withdrawn due to sticker shock from the estimated costs of the required interconnection-related network upgrades. The qualifying requirements, however, disqualify from these requirements interconnection-related transmission needs memorialized in generator interconnection agreements (*i.e.,* that are ready to move forward with project development in the generator interconnection process). Consequently, pursuant to the coordination reformation requirements, no interconnection customer would benefit from having the upgrade costs that it would otherwise pay allocated instead through transmission rates. Rather, in the circumstance that Order No. 1920 addresses, no interconnection customer is willing to pay the estimated costs of the interconnection-related network upgrades. Therefore, there would be no undue preference because if the qualifying criteria are met, there is no longer an interconnection request or interconnection customer associated with the qualifying interconnection-related transmission need.

593. Moreover, in response to PJM's assertion that the output of the RTEP process, which is used in its generator interconnection process, ''would be inflated by the addition of questionable transmission upgrades,'' we again note that the Order No. 1920 requirement does not require that transmission providers resolve interconnection-related transmission needs, including resolving them through selection of transmission facilities; that is, Order No. 1920 neither requires nor guarantees a specific outcome. Rather, transmission providers must consider the interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes and determine whether there is a more efficient or cost-effective transmission solution, under the existing evaluation and selection criteria in the existing Order No. 1000 regional transmission planning and cost allocation processes.

VII. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

A. Order No. 1920 Requirements

594. In Order No. 1920, the Commission required transmission providers in each transmission planning region to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, the following enumerated alternative transmission technologies for each

[1480] *Id.* P 1127.

[1481] *Id.* P 1145.

[1482] *Id.*

[1483] *Id.* P 1111.

[1484] *Id.*

identified transmission need: (1) dynamic line ratings; (2) advanced power flow control devices; (3) advanced conductors; and (4) transmission switching.[1485] This list of enumerated alternative transmission technologies that the Commission required transmission providers in each transmission planning region to consider expanded on the Commission's proposed list of alternative transmission technologies, which only proposed to require the consideration of dynamic line ratings and advanced power flow control devices.[1486] The Commission further required that transmission providers consider each of these enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities. Thus, the Commission required that 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.[1487]

595. The Commission further required that transmission providers' evaluation of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions.[1488] In response to requests for additional transparency, the Commission adopted 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, the Commission required 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.[1489]

B. Requests for Rehearing and Clarification

1. General Requests for Rehearing and Clarification

a. Requests for Rehearing and Clarification

596. Large Public Power requests clarification that transmission providers may use engineering judgment in considering which transmission elements should be analyzed as candidates for alternative transmission technologies. Specifically, Large Public Power explains that, while it does not challenge the Commission's general approach to alternative transmission technologies, requiring transmission providers to conduct resource intensive and detailed production cost simulations for each technology for each existing transmission element would be burdensome and expensive. Large Public Power asks the Commission to clarify that planning engineers may exercise informed discretion regarding the planning horizon within which alternative transmission technologies are of value. Finally, Large Public Power states that it understands that all relevant judgments must be supported and subject to examination and review.[1490]

597. On rehearing, NESCOE argues that the Commission should require transmission providers to prioritize alternative transmission technologies to serve as the starting point for addressing identified transmission needs.[1491] NESCOE states that, absent such prioritization of alternative transmission technologies, rates remain at risk of being unjust and unreasonable.[1492] NESCOE asks the Commission to direct transmission providers to incorporate tariff procedures establishing a rebuttable presumption that the incorporation of alternative transmission technologies as a solution to an identified Long-Term Transmission Need or existing Order No. 1000 transmission need would result in a more efficient or cost-effective transmission solution. NESCOE asserts that such a directive would both maintain the flexibility envisioned by Order No. 1920 and place the burden on transmission providers to demonstrate why alternative transmission technologies are not, either alone or as a solution component, a more efficient or cost-effective solution.[1493]

b. Commission Determination

598. We grant, in part, Large Public Power's request for clarification regarding ''engineering judgment'' in analyzing transmission elements for alternative transmission technologies.[1494] In particular, we do not require detailed production cost simulations to demonstrate costs and benefits of each alternative transmission technology for each existing transmission element, and we clarify that transmission providers have flexibility to apply good engineering judgment to identify the specific transmission elements that are likely candidates for specific enumerated alternative transmission technologies. We recognize that a transmission provider's consideration of alternative transmission technologies will likely depend on the particulars of the transmission provider's transmission system. In that context, transmission providers may be able to rapidly determine if a certain alternative transmission technology is inappropriate for further study on a specific transmission element.[1495]

599. We reiterate, however, that transmission providers in each transmission planning region must consider, as discussed above, dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching for each identified transmission need during Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. We further reiterate that transmission providers must consider each of those alternative transmission technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities.[1496] Such consideration of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions and with the Commission's requirements

[1485] Order No. 1920, 187 FERC ¶ 61,068 at P 1198. In Order No. 1920, the Commission defined advanced transmission technologies as ''a range of permissible present and future technologies, and is defined relative to conventional aluminum conductor steel reinforced conductors.'' *Id.* P 1243. The Commission further clarified that ''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.'' *Id.*

[1486] NOPR, 179 FERC ¶ 61,028 at P 272.

[1487] Order No. 1920, 187 FERC ¶ 61,068 at P 1198.

[1488] *Id.* P 1199.

[1489] *Id.* P 1214.

[1490] Large Public Power Request for Rehearing at 13–16.

[1491] NESCOE Request for Rehearing at 6, 22–25, 34.

[1492] *Id.* at 25.

[1493] *Id.* at 24–25.

[1494] Large Public Power Request for Rehearing at 13–16.

[1495] We note that this is consistent with the Commission's findings in Order No. 2023. *See, e.g.,* Order No. 2023, 187 FERC ¶ 61,068 at P 1590.

[1496] Order No. 1920, 187 FERC ¶ 61,068 at P 1198.

established in Order No. 1920.[1497] Finally, consistent with Large Public Power's understanding,[1498] nothing in this clarification obviates the requirement for transmission providers to support their determinations,[1499] the Commission's transparency requirements, or the potential to challenge a transmission provider's consideration of the enumerated alternative transmission technologies.[1500]

600. We deny NESCOE's request that the Commission establish a rebuttable presumption in favor of alternative transmission technologies.[1501] Rather, it is the Commission's longstanding policy to remain fuel and technology neutral.[1502] As such, and consistent with the Commission's finding in Order No. 2023,[1503] we decline to create a presumption in favor of substituting alternative transmission technologies in either Long-Term Regional Transmission Planning or the existing Order No. 1000 regional transmission planning processes. There is insufficient evidence in the record to presume that an alternative transmission technology would be the more efficient or cost-effective solution as a replacement for a traditional wires-based solution or that the addition of an alternative transmission technology to a potential transmission solution would necessarily result in a more efficient or cost-effective solution in all instances. Consequently, Order No. 1920 mandates a process for the consideration of alternative transmission technologies, not specific outcomes.[1504]

[1497] *Id.* P 1199.

[1498] Large Public Power Request for Rehearing at 16.

[1499] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1214.

[1500] *See, e.g., id.* P 224. The Order No. 890 transmission planning principles include transparency and obligate transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. *See* Order No. 890, 118 FERC ¶ 61,119 at PP 435, 471. In Order No. 890, the transparency transmission planning principle also requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. Order No. 890, 118 FERC ¶ 61,119 at P 471.

[1501] NESCOE Request for Rehearing at 6, 22–25.

[1502] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at P 437 (''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.'').

[1503] Order No. 2023, 184 FERC ¶ 61,054 at P 1582 (''This final rule does not create a presumption in favor of substituting alternative transmission technologies for necessary traditional network upgrades, either categorically or in specific cases.'').

[1504] *See id.*

2. Technology Specific Requests for Rehearing and Clarification

a. Requests for Rehearing and Clarification

601. Clean Energy Associations and PIOs assert that the Commission failed to engage in reasoned decision-making by not requiring transmission providers to evaluate storage resources that perform a transmission function as alternative transmission technologies.[1505] Clean Energy Associations and PIOs disagree that the Commission's finding that ''whether an electric storage resource performs a transmission function requires a case-by-case analysis'' justifies its exclusion from the list of enumerated alternative transmission technologies because, they argue, all transmission solutions are studied on a case-by-case basis.[1506] Clean Energy Associations further argue that whether a particular storage resource is performing a transmission function is completely separate and distinct from the issue of whether a storage resource that *has* been determined on a case-specific basis to be providing a transmission function should be included in the list of enumerated alternative transmission technologies.[1507] Clean Energy Associations argue that the proper approach is to require storage resources that would be providing a transmission function be included in the enumerated list of alternative transmission technologies.[1508]

602. Clean Energy Associations assert that the Commission's decision to exclude storage providing a transmission function is not supported by substantial evidence and is unduly discriminatory.[1509] Clean Energy Associations argue that the record evidence demonstrates that storage can provide efficient or cost-effective solutions and that the Commission did not cite evidence that considering storage in transmission planning is potentially detrimental or lacks stakeholder support.[1510] Clean Energy Associations further argue that the Commission failed to distinguish storage resources providing a transmission function from advanced conductors and transmission switching technologies, which were added to the advanced technologies enumerated in the final rule. Clean Energy Associations assert that there is no rational basis to exclude storage resources from the list and that it is unduly discriminatory to exclude storage.[1511] Clean Energy Associations state that the Commission should grant rehearing and require transmission providers to consider storage as a transmission asset in Long-Term Regional Transmission Planning.[1512]

603. PIOs assert that the Commission's omission of storage as a transmission asset from the list of alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes was arbitrary and capricious because the Commission did not meaningfully engage with commenters or provide a reasoned basis for its decision.[1513] PIOs urge the Commission to grant rehearing to require transmission providers to evaluate storage as a part of Long-Term Regional Transmission Planning.[1514]

604. PIOs observe that the Commission has identified considerations that, together, ensure that a selected storage resource will serve a transmission function; nevertheless, they argue the Commission failed to explain why it did not simply note that the use of storage as a transmission asset will ultimately need to comply with these considerations, rather than omitting it as an alternative transmission technology.[1515] PIOs state that under the Commission's approach in Order No. 1920, in which it explained that ''transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to specific transmission needs,'' it need not dictate how transmission providers evaluate storage as transmission.[1516]

605. CTC Global states that the Commission's definition of advanced conductors allows for the consideration of advanced conductors that are not representative of the capabilities represented by the Commission.[1517]

[1505] Clean Energy Associations Rehearing Request at 26–30; PIOs Rehearing Request at 7, 38–43 (citations omitted).

[1506] Clean Energy Associations Rehearing Request at 26 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1245); PIOs Rehearing Request at 40.

[1507] Clean Energy Associations Rehearing Request at 26.

[1508] *Id.* at 27.

[1509] *Id.* at 26–30.

[1510] *Id.* at 27–28 (citing *Emera Me.,* 854 F.3d at 22).

[1511] *Id.* at 29–30 (citing *FPL Energy Marcus Hook, L.P.* v. *FERC,* 430 F.3d 441, 449 (D.C. Cir. 2005); *Emera Me.,* 854 F.3d at 22).

[1512] *Id.* at 30.

[1513] PIOs Rehearing Request at 38, 42–43 (citations omitted).

[1514] *Id.* at 43.

[1515] *Id.* at 41–42 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1245, n.2671; *Sw. Power Pool, Inc.,* 183 FERC ¶ 61,153, at P 29 (2023)).

[1516] *Id.* at 41 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1210).

[1517] CTC Global Rehearing Request at 2–3.

CTC Global states that this may allow transmission providers to avoid consideration of the types of advanced conductors that Congress intended to be reviewed in the Energy Policy Act of 2005 and that the US DOE has described in reports.[1518] For this reason, CTC Global requests clarification, or in the alternative rehearing, that the definition of advanced conductors will ensure that sufficiently advanced conductors—which at a given voltage increase power flow capabilities by at least 1.5 times, decrease losses by 20% or more, and improve conductor sag performance—are included in regional transmission planning processes. CTC Global states that such a clarification is needed to ensure that the conditions that the Commission identified as leading to unjust and unreasonable rates are addressed and argues that failure to do so will continue to result in project identification that may not be more efficient or cost-effective than alternatives.[1519]

606. Invenergy argues that the Commission should clarify that HVDC is an alternative transmission technology that may be considered in long-term and nearer-term regional transmission planning processes.[1520] Invenergy explains that the Commission did not specifically address the use of HVDC, despite PIOs arguing for its consideration as an alternative transmission technology. Invenergy agrees with PIOs' comments and states that PIOs clearly demonstrated in their comments how HVDC can be beneficial.[1521] In light of this demonstration, Invenergy asks the Commission to grant clarification that transmission providers are not precluded from considering HVDC like other alternative transmission technologies or other potential solutions that may be considered in long-term and nearer-term regional transmission planning processes.[1522]

b. Commission Determination

607. We sustain the Commission's decision in Order No. 1920 to not include storage as a transmission asset in the enumerated list of alternative transmission technologies that transmission providers must consider.[1523] We continue to find that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis of how a particular electric storage resource would be operated as well as any requirements set forth in an OATT governing selection of such electric storage resources as transmission solutions.[1524] Therefore, we continue to find that it is inappropriate to require the consideration of storage that performs a transmission function on a generic basis. While Clean Energy Associations and PIOs argue that any transmission solution requires a case-by-case analysis, electric storage resources require an *additional* case-by-case analysis that distinguishes them from other transmission solutions and from the enumerated list of alternative transmission technologies.[1525] Namely, that type of analysis would require the transmission provider to determine, among other considerations: (1) that the electric storage resource would strictly act as a transmission asset, connected to the transmission system as a transmission facility solely to support that transmission provider's transmission system; (2) the electric storage resource's cost recovery, by ensuring that the electric storage resource's participation in markets is limited to only charging from, and discharging to, the transmission provider's transmission system as necessary to provide the services for which it was selected based on the cost of the maximum capacity needed to address the identified transmission issue; and (3) that the electric storage resource's construction would not impact the generator interconnection queue.[1526] We reiterate, however, that Order No. 1920 does not preclude transmission providers from considering other alternative transmission technologies that were not included in the enumerated list of alternative transmission technologies, including storage as a transmission asset, in their Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.[1527]

608. In response to CTC Global, we clarify that the requirement to consider alternative transmission technologies necessitates that transmission providers consider the types of advanced conductors that Congress intended to be reviewed in the Energy Policy Act of 2005 and that the US DOE has described in its reports.[1528] However, we decline to alter the definition of an advanced conductor.[1529] We continue to find that 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,[1530] and that 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.[1531] However, we clarify that transmission providers, rather than considering just one of the six advanced conductor examples listed, must instead consider each of the six advanced conductor examples listed, and, as they determine appropriate, any additional advanced conductor which that transmission provider determines might be more efficient or cost-effective. In doing so, transmission providers must consider a range of advanced conductor options with a variety of performance and cost attributes, including those with the performance capabilities described by CTC Global.[1532] We deny CTC Global's request to add performance metrics to the definition of an advanced conductor because it would limit the scope of advanced conductors required to be considered and thereby eliminate from

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[1518] *Id.* (citing Energy Policy Act of 2005, Public Law 109–58, 1223, 119 Stat. 594, 953–954 (2005)).

[1519] *Id.* at 2–5, 10–17.

[1520] Invenergy Rehearing Request at 10–13.

[1521] *Id.* at 11–12 (citing PIOs NOPR Initial Comments at 22, Ex. A at PP 20, 22,).

[1522] *Id.* at 13.

[1523] Order No. 1920, 187 FERC ¶ 61,068 at P 1245.

[1524] *Id.* In Order No. 2023, the Commission pointed to the process in SPP, which takes into account five considerations that, together, ensure that a selected electric storage resource will serve a transmission function. Order No. 2023, 184 FERC ¶ 61,054 at P 1599 (citing *Sw. Power Pool, Inc.,* 183 FERC ¶ 61,153, at P 29 (2023)).

[1525] Order No. 2023, 184 FERC ¶ 61,054 at P 1599; Order No. 2023–A, 186 FERC ¶ 61,199 at P 640.

[1526] *Sw. Power Pool, Inc.,* 183 FERC ¶ 61,153, at P 29 (2023).

[1527] Order No. 1920, 187 FERC ¶ 61,068 at P 1247.

[1528] *See, e.g.,* U.S. Dep't of Energy, *Advanced Transmission Technologies* 25–28 (Dec. 2020), *https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf; see also* U.S. Dep't of Energy, *Pathways to Commercial Liftoff: Innovative Grid Deployment* 77 (2024), *https://liftoff.energy.gov/wp-content/uploads/2024/05/Liftoff_Innovative-Grid-Deployment_Final_5.2-1.pdf; see also* 42 U.S.C. 16422(b) (directing the Commission to ''encourage, as appropriate, the deployment of advanced transmission technologies''); *id.* § 16422(a) (defining ''advanced transmission technology'' as ''a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility'').

[1529] *See* CTC Global Rehearing Request at 4–5 (setting forth proposed modified definition).

[1530] Order No. 1920, 187 FERC ¶ 61,068 at P 1198 n.2553.

[1531] *Id.* P 1243.

[1532] CTC Global Rehearing Request at 2–5 (requesting that the Commission clarify that advanced conductors are those that have power flow capabilities that exceed those of conventional aluminum conductor steel reinforced conductors at a given voltage by a factor of at least 1.5 times while decreasing electrical losses by 20% or more, and improve conductor sag performance, at the same or reduced weight per foot).

required consideration certain advanced conductors that may be more efficient or cost-effective in specific circumstances.

609. In response to Invenergy,[1533] we clarify that transmission providers are not precluded from considering HVDC facilities in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. In Order No. 1920, the Commission clarified that transmission providers are not precluded from considering other alternative transmission technologies that are not included in the enumerated list of alternative transmission technologies or other potential solutions in their Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.[1534] That clarification applies to the consideration of HVDC technologies.

VIII. Regional Transmission Cost Allocation

A. Obligation To File an Ex Ante Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop

1. Logical Outgrowth

a. NOPR Proposals

610. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise their OATTs to include one of the following: (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.[1535]

611. The Commission noted that if states agree to a State Agreement Process instead of a Long-Term Regional Transmission Cost Allocation Method, certain Long-Term Regional Transmission Facilities selected in the regional transmission plan for purposes of cost allocation would lack a clear *ex ante* cost allocation method,[1536] and sought comment on whether the Commission should require transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs, in lieu of the proposed reform.[1537] The Commission requested comment on the appropriate outcome when Relevant State Entities fail to agree on a cost allocation method for all or a portion of Long-Term Regional Transmission Facilities, including whether in such circumstances the transmission providers should be required to establish a Long-Term Regional Transmission Cost Allocation Method.[1538]

b. Order No. 1920 Requirements

612. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Methods[1539] for Long-Term Regional Transmission Facilities that are selected and permitted transmission providers to additionally revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process. The Commission required that a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities, and 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.[1540]

613. In Order No. 1920, the Commission stated that it was not imposing 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.[1541]

c. Requests for Rehearing and Clarification

614. Several commenters argue that Order No. 1920 substantially departs from and is not a logical outgrowth of the NOPR because Order No. 1920 does not require transmission providers to adopt a State Agreement Process, consequently denying Relevant State Entities any meaningful opportunity to determine regional cost allocation.[1542] Arizona Commission asserts that, contrary to the NOPR, Order No. 1920 ''effectively eliminates the use of a voluntary State Agreement Process, such as the one that has been used by PJM since Order No. 1000,'' which it asserts is ''directly contrary to comments filed by state regulators.''[1543] Idaho Commission argues that ''[i]n a substantial departure from the NOPR, Order No. 1920 allows, but does 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.''[1544] Designated Retail Regulators similarly contend that Order No. 1920 ''drastically depart[s] from the NOPR'' because it gives transmission providers complete discretion to decide whether to file a State Agreement Process or Long-Term Regional Transmission Cost Allocation method in its OATT, even if agreed to by the Relevant State Entities, which would relegate states to a transmission planning role akin to any other stakeholder.[1545]

615. Designated Retail Regulators and Arizona Commission also contend that Order No. 1920 violates the APA's notice-and-comment requirements because it requires transmission providers to set an *ex ante* cost allocation method that would apply as a backstop in certain circumstances, reducing states' bargaining power and setting up a mechanism to impose a regional cost allocation for preferential

[1533] Invenergy Rehearing Request at 10–13.

[1534] Order No. 1920, 187 FERC ¶ 61,068 at P 1247.

[1535] NOPR, 179 FERC ¶ 61,028 at P 302. The Commission explained that, for example, a ''combination'' approach may entail (i) 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 (ii) 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.

[1536] *Id.* P 315.

[1537] *Id.* P 318.

[1538] *Id.* P 310.

[1539] The Commission defined 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. Order No. 1920, 187 FERC ¶ 61,068 at P 1291.

[1540] *Id.* PP 1291–1292.

[1541] *Id.* P 1429.

[1542] Arizona Commission Rehearing Request at 19; Idaho Commission Rehearing Request at 2, 5–6.

[1543] Arizona Commission Rehearing Request at 19.

[1544] Idaho Commission Rehearing Request at 5 (quotation marks omitted).

[1545] Designated Retail Regulators Rehearing Request at 47–50.

policy and corporate-driven projects when states do not consent.[1546]

d. Commission Determination

616. We find that the Commission's decision in Order No. 1920 not to require that transmission providers adopt a State Agreement Process is a logical outgrowth of the NOPR, and we thus disagree with arguments to the contrary. The NOPR did not propose to require a State Agreement Process but rather proposed to require transmission providers to include in their OATTs *either* a Long-Term Regional Transmission Cost Allocation Method, *or* a State Agreement Process, *or* a combination thereof.[1547] Furthermore, contrary to Arizona Commission's arguments, Order No. 1920 did not eliminate the State Agreement Process and instead permits 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.[1548]

617. We also disagree with Arizona Commission's and Designated Retail Regulators' argument that Order No. 1920's requirement for transmission providers to revise their OATTs to include at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method is not a logical outgrowth of the NOPR proposal to allow transmission providers to choose to include either an *ex ante* regional cost allocation method, or a State Agreement Process, or a combination of both. Although the Commission in the NOPR proposed to allow transmission providers to choose between filing an *ex ante* Long-Term Regional Transmission Cost Allocation Method, a State Agreement Process, or some combination of both, the Commission also sought comment on ''whether the Commission should require, instead of the reforms proposed in this section of the NOPR, public utility transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs.'' [1549] As courts have explained, notice is sufficient when an agency has ''expressly asked for comments on a particular issue or otherwise made clear that the agency was contemplating a particular change.'' [1550] By requesting comment on whether the Commission should require inclusion of an *ex ante* Long-Term Regional Transmission Cost Allocation Method, the Commission put parties on notice that the Commission was considering *the exact change* that it ultimately adopted in Order No. 1920. Therefore, in adopting the requirement that transmission providers file at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method, the Commission adhered to the APA's notice-and-comment requirements.[1551] To the extent Arizona Commission's and Designated Retail Regulators' argument was based on concerns about the states' role more broadly in Long-Term Regional Transmission Planning and cost allocation processes, we note that we adopt a number of modifications and clarifications herein to strengthen the states' role in those processes.[1552]

2. Substantive Issues

a. Order No. 1920 Requirements

618. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise their OATTs to include one or more *ex ante* cost allocation methods that apply to Long-Term Regional Transmission Facilities that are selected in the regional transmission plan for purposes of cost allocation (Long-Term Regional Transmission Cost Allocation Method).[1553]

619. In addition to the required Long-Term Regional Transmission Cost Allocation Method, Order No. 1920 permits transmission providers to revise their OATTs to include a State Agreement Process. However, the Commission found in Order No. 1920 that any State Agreement Process that transmission providers voluntarily propose to include in their OATTs would not comply with the requirements of Order No. 1920 unless Relevant State Entities indicate to the transmission provider that Relevant State Entities have agreed to that process during the Engagement Period.[1554] The Commission also found in Order No. 1920 that a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities.[1555] The Commission explained in Order No. 1920 that, if a State Agreement Process that transmission providers voluntarily include in their OATTs 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 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.[1556]

620. Order No. 1920 does not require transmission providers to obtain state agreement to a cost allocation method for any Long-Term Regional Transmission Facilities and states that the ultimate decision as to which Long-Term Regional Transmission Cost Allocation Method(s) to file on compliance, and whether to file a State Agreement Process to which Relevant State Entities have agreed, lies with transmission providers.[1557]

b. Requests for Rehearing and Clarification

621. On rehearing, a number of parties argue that the Commission's decision in Order No. 1920 to require transmission providers to file an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities will undermine Relevant State Entities' efforts to determine an alternative cost allocation method through a State Agreement Process.[1558] NARUC requests that the Commission adopt the NOPR proposal of mandatory agreement

[1546] Arizona Commission Rehearing Request at 18; Designated Retail Regulators Rehearing Request at 47, 49–50.

[1547] NOPR, 179 FERC ¶ 61,028 at P 302.

[1548] Order No. 1920, 187 FERC ¶ 61,068 at PP 1291–1292.

[1549] NOPR, 179 FERC ¶ 61,028 at P 318.

[1550] *Brennan* v. *Dickson,* 45 F.4th at 69 (quoting *CSX Transp., Inc.* v. *Surface Transp. Bd.,* 584 F.3d at 1081).

[1551] Further, Order No. 1920's requirement that transmission providers revise their OATTs to include at least one *ex ante* Long-Term Regional Transmission Cost Allocation Method separately and independently satisfies the APA's notice-and-comment requirements because courts have indicated that a final rule is a logical outgrowth of a proposal where, as here, an agency adopts only part of a proposal such that ''the final rule [is] not wholly unrelated or surprisingly distant'' from what the agency initially suggested. *Ariz. Pub. Serv. Co.* v. *EPA,* 211 F.3d 1280, 1297–1300 (D.C. Cir. 2000) (finding sufficient notice where agency first proposed that Indian tribes be required to meet the ''same requirements'' as states with respect to judicial review of permits issued pursuant to the Clean Air Act, but then adopted a final rule that exempted tribes from some, though not all, such requirements). Order No. 1920 is a logical outgrowth of the NOPR in this respect because the Commission adopted one of three proposed methods for complying with the requirement—*i.e.,* part of the NOPR proposal—and the challenged provision therefore hews closely to the NOPR proposal such that it is ''not wholly unrelated or surprisingly distant'' from the NOPR proposal. *Id.*

[1552] *See supra* Stakeholder Process and Transparency section; Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section; *infra* Consultation with Relevant State Entities After the Engagement Period section.

[1553] Order No. 1920, 187 FERC ¶ 61,068 at P 1291.

[1554] *Id.; see also id.* PP 1292, 1403.

[1555] *Id.* PP 1292, 1361, 1404.

[1556] *Id.* PP 1291–1292.

[1557] *Id.* PP 1359, 1429; *see also id.* PP 1296, 1363.

[1558] Designated Retail Regulators Rehearing Request at 35–36; Idaho Commission Rehearing Request at 5–6; NARUC Rehearing Request at 12–17; Ohio Commission Federal Advocate Rehearing Request at 8; Undersigned States Rehearing Request at 31–32; Wyoming Commission Rehearing Request at 2–4.

on filed method(s) and/or a State Agreement Process and eliminate the backstop *ex ante* method.[1559] NARUC argues that Order No. 1920's requirement that transmission providers have a backstop Long-Term Regional Transmission Cost Allocation Method in their OATTs undermines Relevant State Entities' negotiation of an alternative cost allocation method and turns such negotiations into a ''check the box'' exercise.[1560] NARUC asserts that allowing transmission providers to ignore or not even report on state input is the definition of an arbitrary and capricious action, and constitutes unreasonable decision making.[1561]

622. Ohio Commission Federal Advocate states that Order No. 1920 arbitrarily and capriciously requires an Engagement Period for states to participate in reaching a cost allocation agreement for Long-Term Regional Transmission Facilities while providing no assurance that it will amount to anything since the final rule allows the transmission provider to have the final say.[1562] Ohio Commission Federal Advocate argues that, because of this, states ultimately have no authority on cost allocation for Long-Term Regional Transmission Facilities.[1563]

623. Designated Retail Regulators and Undersigned States state that Order No. 1920's requirement that transmission providers file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities eliminates the effectiveness of the State Agreement Process, as states are unlikely to agree to a negotiated cost allocation proposal under the State Agreement Process if the default *ex ante* cost allocation results in lower costs for those states.[1564] Designated Retail Regulators and Undersigned States argue that if states jointly agree on a cost allocation process, the rules should require the transmission provider to accept those cost allocation processes, subject to Commission approval.[1565]

624. Wyoming Commission states that the Commission's decision to remove the voluntary state agreement without a backstop reform in the final rule was a significant change from the NOPR, as the NOPR proposal would have allowed states to represent their public policy interests and, in the event of a conflict, prevent other states from exporting their policy decisions and an unreasonable share of related costs to nonconsenting neighbors. Wyoming Commission argues, however, that as a result of reducing states' roles to mere stakeholders in the final rule, the Commission has forced states into agreeing to unjust and unreasonable cost allocations by defaulting to an *ex ante* cost allocation in lieu of requiring a voluntary agreement of the states as a prerequisite.[1566] Wyoming Commission asserts that a voluntary state agreement process is essential to avoid interfering with states' rights with respect to transmission planning and selection, and to prevent nonconsenting states from being ''swept up'' in their neighbors' identified public policy transmission projects.[1567]

625. Idaho Commission argues that by permitting, but not requiring, transmission providers to adopt a State Agreement Process in compliance with Order No. 1920, the states lack a meaningful opportunity to determine a reasonable cost allocation.[1568] Idaho Commission claims that the Commission's reasoning in not requiring a State Agreement Process is unsupported in the record and ignores that Relevant State Entities have statutory duties to ensure fair, just, and reasonable rates for customers.[1569] Idaho Commission further contends that requiring state agreement for cost allocation for Long-Term Regional Transmission Facilities, as the Commission proposed in the NOPR, would have allowed states to represent public policy interests and prevent other states from forcing policy decisions on nonconsenting neighbors. However, Idaho Commission asserts that as a result of Order No. 1920, states now have no meaningful opportunity to determine reasonable cost allocation and will be faced with cost allocation that violates the cost causation principle.[1570]

c. Commission Determination

626. While we sustain the determination in Order No. 1920 that transmission providers in each transmission planning region must file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities, we believe that certain modifications adopted in this order help address, at least in part, concerns raised on rehearing by ensuring that the Commission may consider any Long-Term Regional Transmission Cost Allocation Methods supported by Relevant State Entities.[1571] We believe the balance struck in this order will assist the Commission, with the input of Relevant State Entities, in establishing just and reasonable Long-Term Regional Transmission Cost Allocation Methods that meet the requirements of Order No. 1920.

627. In Order No. 1920, the Commission required that, if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other entities authorized by Relevant State Entities to participate in a State Agreement Process,[1572] a transmission provider chooses not to file an agreed upon cost allocation method, or if the Commission ultimately finds 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. While we sustain the requirement to have a backstop Long-Term Regional Transmission Cost Allocation Method on file, we revise the portion of this requirement related to the transmission providers' choice as to whether to file Long-Term Regional Transmission Cost Allocation Methods and/or State Agreement Processes agreed to by Relevant State Entities, as discussed in further detail below.[1573]

628. Turning to the rehearing requests challenging the requirement to have an *ex ante* cost allocation method on file, we disagree with Wyoming Commission and Idaho Commission that this requirement forces states into agreeing to unjust and unreasonable cost allocations that allow states to foist the cost of their policy decisions on nonconsenting neighbors.[1574] Under the NOPR proposal, the Commission proposed that transmission providers in each transmission planning region file OATTs to include either (1) a Long-

[1559] NARUC Rehearing Request at 12–17.

[1560] *Id.* at 16.

[1561] *Id.* at 15.

[1562] Ohio Commission Federal Advocate Rehearing Request at 7–8.

[1563] *Id.* at 8.

[1564] Designated Retail Regulators Rehearing Request at 35–36; Undersigned States Rehearing Request at 31–32.

[1565] Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31.

[1566] Wyoming Commission Rehearing Request at 2–3.

[1567] *Id.* at 3.

[1568] Idaho Commission Rehearing Request at 5–6.

[1569] *Id.*

[1570] *Id.*

[1571] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1572] Order No. 1920, 187 FERC ¶ 61,068 at P 1402 (noting that Relevant State Entities have the option to include the participation of other entities in a State Agreement Process).

[1573] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1574] *See* Idaho Commission Rehearing Request at 5–6; Wyoming Commission Rehearing Request at 3.

Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof.[1575] Pursuant to the FPA, the Commission may accept only proposed rates, terms, and conditions that are just and reasonable. Therefore, the Commission could not accept a cost allocation method that would force states into agreeing to unjust and unreasonable cost allocations, and any just and reasonable cost allocation method must ensure that the costs of Long-Term Regional Transmission Facilities are allocated in a manner that is at least roughly commensurate with the estimated benefits.[1576]

629. We also disagree with arguments that the State Agreement Process will ultimately be a ''check the box'' exercise or that requiring an *ex ante* Long-Term Regional Transmission Cost Allocation Method otherwise limits the effectiveness of a State Agreement Process.[1577] Order No. 1920 places an affirmative obligation on transmission providers to supply a forum for states to negotiate cost allocation,[1578] providing ample room for states to allocate costs in a manner that they agree to,[1579] and, as discussed below, in this order we require transmission providers to include in the transmittal or as an attachment to their compliance filing any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities agree upon.[1580] Relevant State Entities may structure the processes used to determine those cost allocation methods in a manner that would require a level of agreement of their choosing, including, as one potential option, unanimity.[1581] In this order, we also establish a requirement that transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.[1582] And as we have already discussed, transmission providers shall develop a reasonable number of additional scenarios, when requested by Relevant State Entities, for the purposes of informing the application of Long-Term Regional Transmission Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es).[1583]

630. To the extent that Wyoming Commission argues that requiring an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities intrudes on states' rights with respect to transmission planning and selection, we disagree. We note that the D.C. Circuit held that requiring *ex ante* cost allocation methods under Order No. 1000 regional transmission planning does not intrude on state authority.[1584] We continue to find that Long-Term Regional Transmission Planning is a subset of regional transmission planning that closes specific gaps of the existing Order No. 1000 framework without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal.[1585]

631. With respect to the assertion that states are unlikely to agree to a negotiated cost allocation proposal under the State Agreement Process if the default *ex ante* cost allocation results in lower costs for those states, we note that Order No. 1920 provides Relevant State Entities with the opportunity to negotiate *ex ante* cost allocation methods in the first instance, and we take steps in this order to further enable states to do so.[1586] Further, states are likely to have an incentive to negotiate with other states in order to ensure timely and efficient development of Long-Term Regional Transmission Facilities that benefit their ratepayers, but would not be developed without the support of other states. We find that the opportunity for Relevant State Entities to negotiate *ex ante* cost allocation methods in the first instance and agree to a State Agreement Process, coupled with the benefits of certainty provided by a backstop *ex ante* cost allocation method, strike a reasonable balance, and we otherwise sustain, as explained in greater detail below, the Commission's finding in Order No. 1920 that requiring transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs is necessary to ensure that Commission-jurisdictional rates are just and reasonable.[1587]

632. We disagree with Idaho Commission's contention that Order No. 1920 denies Relevant State Entities any meaningful opportunity to determine reasonable cost allocation methods.[1588] We recognize the critical role that states play in regional transmission planning and that Relevant State Entities have their own statutory obligations. As discussed in Order No. 1920, and expanded upon here,[1589] we are placing an affirmative obligation on transmission providers to provide a meaningful opportunity for Relevant State Entities to share their views on cost allocation during the Engagement Period, during subsequent implementation of a State Agreement Process to which the Relevant State Entities have agreed that has been filed by a transmission provider and accepted by the Commission,[1590] and, as described herein, before future cost

[1575] NOPR, 179 FERC ¶ 61,028 at P 302.

[1576] Order No. 1920, 187 FERC ¶ 61,068 at PP 1510, 1515; *see, e.g., 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.''); Order No. 1000, 136 FERC ¶ 61,051 at P 690 (''If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.'').

[1577] NARUC Rehearing Request at 16; Ohio Commission Federal Advocate Rehearing Request at 7–8; Designated Retail Regulators Rehearing Request at 35–36; Undersigned States Rehearing Request at 31–32.

[1578] Order No. 1920, 187 FERC ¶ 61,068 at PP 1354, 1356–1357.

[1579] *Id.* PP 1415–1416.

[1580] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1581] Order No. 1920, 187 FERC ¶ 61,068 at P 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.'').

[1582] *See infra* Consultation with Relevant States Entities After the Engagement Period section.

[1583] *See supra* Requests for Additional Flexibility Regarding Long-Term Scenarios Requirements section.

[1584] *See S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 55–59, 62–64, 82–89; *id.* at 64 ((''[W]e hold that [Order No. 1000] does not interfere with the traditional state authority that is preserved by [FPA] Section 201 . . . .'').

[1585] Order No. 1920, 187 FERC ¶ 61,068 at P 256 (citing *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))).

[1586] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section.

[1587] Order No. 1920, 187 FERC ¶ 61,068 at P 1293.

[1588] Idaho Commission Rehearing Request at 5–6.

[1589] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section.

[1590] Order No. 1920, 187 FERC ¶ 61,068 at P 1296.

allocation amendments.[1591] Relevant State Entities therefore have a meaningful opportunity to participate in cost allocation decisions related to Long-Term Regional Transmission Facilities.

633. We continue to find that 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 did not result in agreement on a cost allocation method, 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.[1592] As a result, these 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.[1593] Furthermore, we continue to find that, if these selected Long-Term Regional Transmission Facilities were not ultimately built, 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.[1594]

634. In addition, we are concerned that a state-agreement requirement could lead to a situation in which a transmission project was planned based on benefits that it provides to customers in several states, and that, if one or more of those states declined to voluntarily agree to a cost allocation method, it would raise free-ridership concerns.[1595] For that reason, sole reliance on a State Agreement Process has the potential to 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.[1596] The level of certainty for transmissions providers in having a Long-Term Regional Transmission Cost Allocation Method on file, even when a State Agreement Process is used, remains critical to the development of needed Long-Term Regional Transmission Facilities.[1597]

B. Requirements Concerning Relevant State Entities

1. Requested Requirement To Obtain the Agreement of Relevant State Entities

a. Order No. 1920 Requirements

635. In Order No. 1920, the Commission declined 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, the Commission modified the NOPR proposal to establish a six-month time period (Engagement Period), during which transmission providers must, among other requirements, 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.[1598]

b. Requests for Rehearing and Clarification

636. Undersigned States and Designated Retail Regulators argue that the Engagement Period is not a ''fair replacement of a requirement for regulator consent'' because Order No. 1920 does not require transmission providers to propose on compliance a Long-Term Regional Transmission Cost Allocation Method agreed to by the states.[1599] Undersigned States and Designated Retail Regulators further argue that Order No. 1920's lack of a requirement for transmission providers to obtain the consent of retail regulators on the cost allocation method(s) that apply to Long-Term Regional Transmission Facilities usurps state authority because it enables the ratepayers of non-consenting states to be assessed the costs of the public policy projects of other states and speculative investment based on conjecture about future resource trends.[1600] Designated Retail Regulators argue that existing regulator organizations such as OMS ''may not be the best forums to confect state agreements'' because the ''authority to reach agreement on cost allocation rests in each State'' and cannot be delegated to such organizations in order to reach general consensus on issues.[1601]

c. Commission Determination

637. While we sustain our decision not to adopt the NOPR proposal and instead establish the Engagement Period for cost allocation negotiations, we believe that certain modifications in this order help address, at least in part, the concerns raised by Designated Retail Regulators and Undersigned States by providing additional opportunities for Relevant State Entities to help establish just and reasonable cost allocation methods for Long-Term Regional Transmission Facilities.[1602]

638. Turning to Designated Retail Regulators' and Undersigned States' arguments, the Commission did not propose in the NOPR to require transmission providers to obtain the consent of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Rather, the Commission proposed to require transmission providers to seek the agreement of Relevant States Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.[1603] In Order No. 1920, the Commission did not adopt the requirement for transmission providers to seek the agreement of Relevant State Entities (while affording transmission providers flexibility in the process by which they seek agreement

[1591] *See infra* Consultation with Relevant State Entities After the Engagement Period section.

[1592] Order No. 1920, 187 FERC ¶ 61,068 at P 1293.

[1593] *Id.*

[1594] *Id.*

[1595] *See El Paso Elec. Co.* v. *FERC,* 76 F.4th at 361–63 (''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)); 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.'').

[1596] Order No. 1920, 187 FERC ¶ 61,068 at P 1293 (citation omitted).

[1597] *Id.*

[1598] *Id.* P 1354.

[1599] Designated Retail Regulators Rehearing Request at 36; Undersigned States Rehearing Request at 32.

[1600] Designated Retail Regulators Rehearing Request at 36–39; Undersigned States Rehearing Request at 32–35.

[1601] Designated Retail Regulators Rehearing Request at 38.

[1602] *See infra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section; Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

[1603] Order No. 1920, 187 FERC ¶ 61,068 at P 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.'' (emphasis added)). We address arguments concerning the Commission's decision not to require transmission providers to seek the agreement of Relevant State Entities in the Requests Arguing the Engagement Period is Inferior to a Requirement that Transmission Providers Seek the Agreement of Relevant State Entities section below.

from the Relevant State Entities) and instead adopted a requirement for transmission providers to provide a forum for states to meaningfully participate in negotiating cost allocation methods.[1604]

639. With respect to requests that we *require* agreement of state regulators for any cost allocation method for Long-Term Regional Transmission Facilities, we continue to find that the views of state regulators regarding the appropriate cost allocation approach are important, but ultimately the transmission provider is the public utility that must respond and comply with Order No. 1920.[1605] Furthermore, the Commission has a statutory responsibility to review the compliance filings from transmission providers to ensure that any proposed cost allocation is just and reasonable and not unduly discriminatory or preferential, and Order No. 1920 recognizes these statutory roles.[1606] Nonetheless, we reiterate that robust state engagement can valuably inform a cost allocation approach and, as discussed further below, we take steps in this order to further that engagement.

640. In response to Designated Retail Regulators' and Undersigned States' argument that Order No. 1920's lack of a requirement for transmission providers to obtain the consent of states on the cost allocation method(s) that apply to Long-Term Regional Transmission Facilities enables the ratepayers of non-consenting states to be assessed the costs of other states' public policies and speculative investment,[1607] in addition to the steps to further state engagement taken herein, we note that all cost allocation methods for Long-Term Regional Transmission Facilities, including Long-Term Regional Transmission Cost Allocation Methods and cost allocation methods resulting from State Agreement Processes, must allocate the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with the estimated benefits, consistent with legal precedent.[1608] We find that this requirement addresses Designated Retail Regulators' and Undersigned States' concern that Order No. 1920's requirements will result in non-consenting states paying for costs they did not cause.

641. In response to Designated Retail Regulators' assertion that the ''authority to reach agreement on cost allocation rests in each State'' and that this authority cannot be ''delegated to organizations that States participate in to attempt to reach general consensus on issues,'' [1609] we note that Order No. 1920 did not require transmission providers to use existing mechanisms for state involvement in regional transmission planning and cost allocation processes, such as the SPP Regional State Committee and OMS, as a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[1610] In fact, Order No. 1920 specified that it is Relevant State Entities—and not transmission providers—who may choose to use such an existing mechanism to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process.[1611] Similarly, the Commission left to the Relevant State Entities participating in the Engagement Period matters including what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement.[1612]

2. Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods

a. Order No. 1920 Requirements

642. In Order No. 1920, the Commission found that, 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(s) and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement, the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. The Commission noted, 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.[1613] In addition, the Commission found that its directives in Order No. 1920 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 that would govern subsequent filings regarding the cost allocation for Long-Term Regional Transmission Facilities.[1614] The Commission did 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 OATT.[1615]

b. Requests for Rehearing and Clarification

643. NARUC, PJM States, Designated Retail Regulators, Undersigned States, and West Virginia Commission request rehearing of Order No. 1920's decision not to require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period.[1616] NARUC argues that Order No. 1920 ''arbitrarily and without adequate explanation removes protections proposed in the NOPR for states and their ratepayers by not requiring [t]ransmission [providers] to incorporate state consensus to cost allocation methods for filing as part of the OATT.'' [1617] PJM States argue that, absent such a requirement, state engagement in the development of cost allocation methods for Long-Term Regional Transmission Facilities is not likely to materialize. PJM States argue that, by contrast, incenting state agreement (and the filing of that agreement) makes it more likely that Order No. 1920's goals are met, as a state-agreed upon cost allocation method has a lower burden of proof than a transmission provider filing without state agreement.[1618] West

[1604] *See id.* PP 1354, 1357.

[1605] *Id.* P 1363.

[1606] *Id.*

[1607] Designated Retail Regulators Rehearing Request at 37–38; Undersigned States Rehearing Request at 33.

[1608] *See supra* P 628 n.1577.

[1609] *See* Designated Retail Regulators Rehearing Request at 38.

[1610] Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1611] *Id.*

[1612] *Id.* P 1360.

[1613] *Id.* PP 1359, 1363.

[1614] *Id.* P 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, consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO.'') (citation omitted).

[1615] *Id.* PP 1359, 1429.

[1616] NARUC Rehearing Request at 12; PJM States Rehearing Request at 2–3; Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31; West Virginia Commission Rehearing Request at 13–14.

[1617] NARUC Rehearing Request at 12.

[1618] PJM States Rehearing Request at 2–3 (citing Order No. 1920, 187 FERC ¶ 61,068 at PP 1469, 1472, 1476).

Virginia Commission agrees with PJM States and argues that the Commission should either require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period or ''grant the States 205 filing rights as it pertains to State-agreed cost allocation methods.'' [1619]

644. PIOs, PJM States, and NARUC request clarification that, where a particular cost allocation method garnered state support during the Engagement Period and the transmission provider elects not to adopt that method in its compliance filing, the transmission provider must include the states' preferred cost allocation method in its compliance filing and explain why that method was not used.[1620] West Virginia Commission requests the same clarification in the alternative to its request that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period.[1621] West Virginia Commission requests that the Commission require transmission providers to include the states' preferred cost allocation method ''for informational purposes.'' [1622] NARUC further requests that the Commission clarify that transmission providers' compliance filings must also include a general description of the discussions during the Engagement Period, including transmission providers' outreach to Relevant State Entities.[1623] Similarly, NARUC, PJM States, and Virginia and North Carolina Commissions request that the Commission clarify that transmission providers must disclose the extent to which states agreed or disagreed with the filed cost allocation method.[1624] PIOs also request that the Commission clarify that: (1) transmission providers must ''clearly disclose and explain the outcome'' of the Engagement Period; (2) the Commission will carefully evaluate the existence of a state agreement regarding cost allocation and any departure from that agreement in reviewing cost allocation methods proposed by transmission providers on compliance; and (3) transmission providers must explain how their chosen cost allocation methods are just and reasonable and not unduly discriminatory or preferential. PIOs contend that their requested clarifications would offer states additional confidence that participation in the Engagement Period will be meaningful.[1625]

645. NESCOE requests rehearing of Order No. 1920's decision to not require transmission providers to file states' preferred cost allocation method along with transmission providers' own preferred cost allocation method. NESCOE argues that because states are not public utilities, absent language in the transmission providers' organizational documents or OATTs, states are unable to file cost allocation methods themselves. NESCOE argues that ''[r]elegating states to commenting on a transmission provider's cost allocation filing does not enable the states to put before the Commission their preferred cost allocation method; rather, it shifts the burden to states to show that the transmission provider's FPA section 205 filing is not just and reasonable.'' [1626] NESCOE contends that Order No. 1920 envisions that the only path for states to have their preferred cost allocation method approved would be through a complaint proceeding in which states would bear the burden of first proving that a transmission provider's Commission-approved cost allocation method is unjust and unreasonable.[1627] NESCOE argues that requiring each transmission provider to file states' preferred cost allocation method alongside its own would comport with precedent holding that the Commission may not require transmission providers '' 'to cede rights expressly given to them' in FPA section 205.'' [1628] In the alternative, NESCOE requests that the Commission strongly encourage transmission providers to ''voluntarily codify existing or new approaches on compliance'' that would facilitate transmission providers' filing of alternative region-wide state agreement on cost allocation, such as the approaches used in the NYISO and SPP regions.[1629] NESCOE opines that ''[i]ncluding the state-agreed upon cost allocation method in a transmission provider's section 205 filing is a lawful and rational means to effectuate in a concrete way the respect for the state role the Commission articulates.'' [1630]

646. Harvard ELI requests that the Commission grant rehearing by requiring transmission providers to revise their OATTs to include a process for filing all regional cost allocation methods approved by Relevant State Entities.[1631] Harvard ELI contends that, by not requiring transmission providers to file all cost allocation methods agreed to by Relevant State Entities, Order No. 1920 fails to remedy unjust and unreasonable cost allocation processes.[1632] Harvard ELI argues that such a requirement would not violate the D.C. Circuit's holding in *Atlantic City* because it would neither ''deny utilities their right to unilaterally file rate and term changes'' nor ''force public utilities to file particular rates.'' [1633] Harvard ELI argues that, because the Commission ''has authority to approve utility filing rights arrangements under FPA section 205,'' it also has the authority under FPA section 206 to order changes to filing processes and may do so here to require transmission providers to file all cost allocation methods approved by the Relevant State Entities.[1634] In the alternative, Harvard ELI requests that the Commission clarify that it did not intend to imply that it lacks authority under FPA section 206 to amend the *pro forma* OATT to include a process for filing all regional cost allocation methods approved by Relevant State Entities.[1635]

647. NARUC requests that the Commission provide a mechanism to ensure that transmission providers ''remain in compliance with the requirement to include [R]elevant [S]tate [E]ntities in cost allocation for Long-Term Regional Transmission Facilities.'' [1636] NARUC asserts that the Commission should either require transmission providers to periodically open new Engagement Periods or require transmission providers to file a

[1619] West Virginia Commission Rehearing Request at 13–14.

[1620] NARUC Rehearing Request at 17–18; PIOs Rehearing Request at 55–57; PJM States Rehearing Request at 7–8.

[1621] West Virginia Commission Rehearing Request at 9.

[1622] *Id.*

[1623] NARUC Rehearing Request at 17–18.

[1624] *Id.* at 17; PJM States Rehearing Request at 7; Virginia and North Carolina Commissions Rehearing Request at 10.

[1625] PIOs Rehearing Request at 54–57.

[1626] NESCOE Rehearing Request at 14–15.

[1627] *Id.* Vermont Commission states that it supports the NESCOE Rehearing Request, including strengthening the state role in all phases of Long-Term Regional Transmission Planning, and specifically cost allocation. Vermont Commission Rehearing Request at 1–2.

[1628] NESCOE Rehearing Request at 15 (quoting *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 9).

[1629] *Id.* at 15–16 (citing NESCOE NOPR Initial Comments at 69–70 (citing *N.Y. Indep. Sys. Operator, Inc.,* 151 FERC ¶ 61,040, at P 119 (2015) (*NYISO*); SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), § 7.2)).

[1630] *Id.* at 16.

[1631] Harvard ELI Rehearing Request at 1–3.

[1632] *Id.* at 6 (stating that 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'' (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 126)).

[1633] *Id.* at 4–5 (alteration omitted) (quoting *Atl. City Elec. Co.* v. *FERC,* 295 F.3d at 10).

[1634] *Id.* at 4.

[1635] *Id.* at 1, 8–9.

[1636] NARUC Rehearing Request at 21–22.

modification to their OATTs if states reach the requisite agreement on a different cost allocation method than that reflected in the transmission providers' OATTs.[1637]

648. PIOs request clarification that transmission providers may, in their compliance filings, voluntarily commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation method will be put before the Commission for approval.[1638]

c. Commission Determination

649. As the Commission recognized in Order No. 1920, and we reiterate in this order, it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes.[1639] At the same time, the Commission has an independent responsibility to ensure that those cost allocation methods conform to the cost causation principle and are otherwise just and reasonable and not unduly discriminatory or preferential.

650. To address these considerations and the concerns raised on rehearing, we simultaneously (1) expand Relevant State Entities' opportunities to inform and provide alternatives to the transmission providers' proposed Long-Term Regional Transmission Cost Allocation Method, and (2) sustain Order No. 1920's determination that transmission providers retain the right to determine which cost allocation methods for Long-Term Regional Transmission Facilities they will propose on compliance. Accordingly, while we decline rehearing parties' requests that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, we take steps to ensure that the Commission may consider the Relevant State Entities' preferred Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, to the extent those differ from the Method(s) filed by transmission providers on compliance.

651. To that end, we set aside Order No. 1920, in part, and require that when Relevant State Entities notify transmission providers by the deadline for communicating agreement[1640] that they agree on a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process resulting from the Engagement Period, the transmission providers must include that method or process in the transmittal or as an attachment to their compliance filing, even if the transmission providers propose a different Long-Term Regional Transmission Cost Allocation Method or do not propose to adopt a State Agreement Process. We further direct transmission providers to include in the transmittal or as an attachment to their compliance filings any information that Relevant State Entities provide to them regarding the state negotiations during the Engagement Period. We also set aside Order No. 1920, in part, to require that, upon the request of Relevant State Entities, transmission providers must facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities.

652. At the outset, in response to arguments concerning the Commission's authority to impose the various cost allocation requirements proposed by parties on rehearing,[1641] we reiterate that the Commission in Order No. 1920 determined that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential under FPA section 206.[1642] The Commission thus had both the authority and responsibility to ''determine the just and reasonable . . . practice . . . to be thereafter observed and in force,''[1643] consistent with Order No. 1920's findings. Pursuant to its authority under FPA section 206, the Commission required transmission providers to submit on compliance an *ex ante* cost allocation method. This compliance filing submitted pursuant to FPA section 206 is not an FPA section 205 filing,[1644] and is thus distinct from any FPA section 205 filing that a transmission provider might file in the future following compliance to propose a change to its cost allocation method(s) for Long-Term Regional Transmission Facilities.[1645]

653. We believe the balance struck herein should address, at least in part, the concerns driving the rehearing requests of NARUC, PJM States, Designated Retail Regulators, Undersigned States, and West Virginia Commission, who request that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, and NESCOE, which argues that the Commission should require transmission providers to propose on compliance Relevant State Entities' preferred cost allocation method along with transmission providers' preferred cost allocation method.[1646] While we continue to find that robust state engagement is valuable to informing cost allocation,[1647] we also recognize transmission providers, subject to Commission oversight, remain ultimately responsible for transmission planning,[1648] which we find is fundamentally linked with cost allocation.[1649] Consistent with this responsibility, while reiterating the balance the Commission seeks to strike

[1637] *Id.* In the Consultation with Relevant State Entities After the Engagement Period section below, we discuss NARUC's request that the Commission require transmission providers to periodically open a new negotiation period with Relevant State Entities concerning cost allocation for Long-Term Regional Transmission Facilities.

[1638] PIOs Rehearing Request at 55–56.

[1639] *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at P 1415.

[1640] Order No. 1920 requires that transmission providers in each transmission planning region provide notice, such as on its OASIS page or public website, of the deadline for Relevant State Entities to communicate their agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, and this deadline must be no earlier than the end date of the Engagement Period. *Id.* P 1356.

[1641] *E.g.,* Harvard ELI Rehearing Request at 4; NESCOE Rehearing Request at 15.

[1642] Order No. 1920, 187 FERC ¶ 61,068 at PP 113–114; *supra* The Overall Need for Reform section.

[1643] 16 U.S.C. 824e(a).

[1644] *See ISO New England Inc.,* 165 FERC ¶ 61,202 (2018), *order on reh'g,* 173 FERC ¶ 61,204, at P 8 (2020) (clarifying that the Commission would review ISO–NE's proposed tariff revisions as a new FPA section 205 filing, rather than a compliance filing, because the Commission had not previously made ''a finding that ISO–NE's tariff was unjust and unreasonable without such revisions, a necessary precursor to the Commission considering ISO–NE's tariff revisions as a compliance filing setting forth a proposed replacement rate'').

[1645] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1430. As discussed below in the Consultation with Relevant State Entities After the Engagement Period section, we adopt, as part of this rule, a requirement that transmission providers revise their OATTs to add a requirement that they consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

[1646] NARUC Rehearing Request at 12; NESCOE Rehearing Request at 14–15; PJM States Rehearing Request at 2–3; Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31; West Virginia Commission Rehearing Request at 13–14.

[1647] Order No. 1920, 187 FERC ¶ 61,068 at P 1363.

[1648] *Id. See also* Order No. 1000, 136 FERC ¶ 61,051 at P 153; Order No. 890, 118 FERC ¶ 61,119 at P 454.

[1649] Order No. 1000, 136 FERC ¶ 61,051 at P 559 (''[T]here is a fundamental link between cost allocation and planning, as it is through the planning process that benefits, which are central to cost allocation, can be assessed.'').

in this order regarding the role of Relevant State Entities, we decline to require transmission providers, on compliance, to propose to adopt a State Agreement Process or Long-Term Regional Transmission Cost Allocation Method to which Relevant State Entities agreed, particularly if transmission providers prefer an alternative approach to cost allocation.

654. However, we are persuaded by PIOs', PJM States', and NARUC's arguments that the Commission should consider any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement process to which the Relevant State Entities agree. We agree that the Commission should require transmission providers to include in the transmittal of their compliance filings any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process to which the Relevant State Entities agreed but that transmission providers elect not to propose to comply with Order No. 1920.[1650] Therefore, we set aside Order No. 1920, in part, and require that, when Relevant State Entities communicate to transmission providers by the deadline for communicating agreement that they agree on a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process resulting from the Engagement Period, the transmission providers must include that method or process in the transmittal or as an attachment to their compliance filings, even if the transmission providers propose to adopt a different Long-Term Regional Transmission Cost Allocation Method or do not propose to revise their tariffs to include a State Agreement Process.[1651] We continue to decline to define what constitutes agreement among Relevant State Entities,[1652] but we note that, at the choosing of the Relevant State Entities in a transmission planning region, existing relevant state committee processes may guide Relevant State Entities in defining what constitutes agreement, such as the processes of OMS and NESCOE.

655. We are also persuaded by NARUC's, PIOs', PJM States', and Virginia and North Carolina Commissions' arguments that the Commission should require transmission providers to provide additional information related to Relevant State Entities' participation in the Engagement Period even when transmission providers propose on compliance a separate cost allocation method and/or decline to propose a State Agreement Process,[1653] and we therefore further direct transmission providers to include in the transmittal or as an attachment to their compliance filings any information that any Relevant State Entities provide to them regarding the state negotiations during the Engagement Period. As part of this requirement, we clarify that transmission providers must include any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing. We expect that the information that Relevant State Entities provide to transmission providers could include, for example, a description of the discussions that took place at the Engagement Period forum for negotiation and whether each Relevant State Entity agreed or disagreed with the cost allocation method proposed on compliance. However, we decline to require transmission providers to independently characterize this information. For example, we do not require transmission providers to separately characterize Relevant State Entities' agreement or independently justify Relevant State Entities' preferred Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process. We find that a requirement for transmission providers to include in the transmittal or as an attachment to their compliance filings the information received from any Relevant State Entities during the Engagement Period will sufficiently capture the results of the Engagement Period.

656. Furthermore, upon review of the requests for rehearing and clarification about the Engagement Period, we also believe that Relevant State Entities would benefit from the assistance of transmission providers in some cases, as transmission providers may have more experience with the transmission providers' OATTs and with the Commission's processes and precedent. Therefore, we set aside Order No. 1920, in part, and now include a requirement that upon the request of Relevant State Entities, transmission providers must facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities.

657. We find that these additional requirements will allow the Commission to better evaluate whether transmission providers have complied with Order No. 1920's requirement to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period.[1654] Furthermore, given that we direct these facilitation and informational requirements on compliance pursuant to the Commission's authority under FPA section 206, we find that these requirements do not implicate or infringe upon transmission providers' filing rights under FPA section 205.

658. When acting under FPA section 206, the Commission's statutory burden is to establish *a* just and reasonable and not unduly discriminatory replacement rate that is supported by substantial evidence.[1655] The statute does not necessarily require the Commission to adopt the transmission provider's proposal on compliance, even if that proposal complies with the final rule's requirements. Rather, the Commission need only select a replacement rate that complies with the final rule and that is adequately supported in the record, and then intelligibly explain the reasons for its choice.[1656]

659. We recognize that the Commission generally does not consider alternate compliance proposals other than those filed by the relevant public utility (here, the transmission provider).[1657] Nevertheless, as the Commission explained in Order No. 1920, and as we reiterate on rehearing, there are ''good reasons'' for considering such alternatives here with respect to

[1650] *See* NARUC Rehearing Request at 17–18; PIOs Rehearing Request at 55–57; PJM States Rehearing Request at 7–8.

[1651] We clarify that, under this approach, the transmission providers decide what to submit as their actual Order No. 1920 compliance proposal, including relevant tariff language and supporting evidence or arguments, whether they decide to propose the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process or a different Long-Term Regional Transmission Cost Allocation Method. The requirement to include Relevant State Entities' Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process as an addition to the compliance filing does not constitute a ''proposal'' from the transmission provider.

[1652] Order No. 1920, 187 FERC ¶ 61,068 at P 1360.

[1653] NARUC Rehearing Request at 17; PIOs Rehearing Request at 54–57; PJM States Rehearing Request at 7; Virginia and North Carolina Commission Rehearing Request at 10.

[1654] Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1655] 16 U.S.C. 824e; 16 U.S.C 825*l*(b).

[1656] *See Entergy Ark., LLC* v. *FERC,* 40 F.4th 689, 701–02 (D.C. Cir. 2022) (noting that the Commission ''is not required to choose the best solution, only a reasonable one'') (first quoting *Petal Gas Storage, LLC* v. *FERC,* 496 F.3d 695, 703 (D.C. Cir. 2007); and then quoting *EPSA,* 577 U.S. at 295).

[1657] *See, e.g., PJM Interconnection, L.L.C.,* 173 FERC ¶ 61,134, at P 117 n.175 (2020); *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,318, at P 115 (2007); *ANR Pipeline Co.,* 110 FERC ¶ 61,069, at P 49 (2005).

cost allocation under Order No. 1920.[1658] States play a unique role in Long-Term Regional Transmission Planning, as their laws, regulations, and policies drive the need for Long-Term Regional Transmission Facilities,[1659] and they typically will have responsibility to consider and approve the siting, permitting, and construction of Long-Term Regional Transmission Facilities selected in a regional transmission plan. As such, states affect whether Long-Term Regional Transmission Facilities are timely, efficiently, and cost-effectively developed such that customers actually receive the benefits associated with the selection of more efficient or cost-effective transmission solutions.[1660] We further find that, given the inherent uncertainty involved in planning to meet Long-Term Transmission Needs,[1661] state-developed cost allocation methods and State Agreement Process take on heightened importance. This means that the Commission will consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate. Specifically, when the Commission reviews transmission providers' compliance filings, the Commission is not required to accept a cost allocation proposal from a transmission provider simply because it may comply with Order No. 1920. Instead, the Commission may adopt any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920.[1662]

660. We believe Order No. 1920, as modified here on rehearing, strikes a reasonable balance between, on the one hand, recognizing the rights and responsibilities of the Commission and transmission providers over regional transmission planning and, on the other, the states' critical interests in the resulting Long-Term Regional Transmission Facilities and how the costs associated with those facilities will be allocated. We also believe that this balance, including the requirement that transmission providers consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process,[1663] addresses, at least in part, concerns underlying arguments by Harvard ELI and NARUC that the Commission should establish a prospective mechanism through which transmission providers would be required to file for Commission approval any cost allocation methods approved by Relevant State Entities[1664] or if states reach the requisite agreement on a different cost allocation method than that reflected in the OATT then on file.[1665]

661. Nonetheless, consistent with our findings above with respect to requests that the Commission require transmission providers to adopt any cost allocation method that Relevant State Entities agree upon during the Engagement Period, we decline to adopt Harvard ELI's and NARUC's proposals. Transmission planning is the tariff obligation of each transmission provider and transmission providers retain, subject to Commission oversight, responsibility for regional transmission planning, including Long-Term Regional Transmission Planning, as well as complying with the obligations of Order No. 1920.[1666] We disagree with Harvard ELI's contention that Order No. 1920's cost allocation requirements fail to remedy unjust and unreasonable cost allocation processes because Order No. 1920 does not require transmission providers to file all cost allocation methods approved by Relevant State Entities.[1667] As discussed below,[1668] we find that the Engagement Period established in Order No. 1920 provides the "dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods"[1669] that the Commission recognized was absent from existing cost allocation requirements. We further find that, combined with existing opportunities for state engagement in the development of regional cost allocation methods along with those established herein,[1670] Order No. 1920's cost allocation requirements remedy the unjust, unreasonable, and unduly discriminatory or preferential existing regional cost allocation requirements.

662. In response to PIOs' request that the Commission clarify that transmission providers may voluntarily commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation will be put before the Commission for approval,[1671] and NESCOE's request that the Commission strongly encourage transmission providers to commit to such processes,[1672] we reiterate that transmission providers may voluntarily adopt a process in their OATTs, whether it be a State Agreement Process or another Commission-approved process, under which they commit to file with the Commission pursuant to FPA section 205 any cost allocation method that garners state agreement subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920.[1673] We also agree with NESCOE's request and strongly encourage transmission providers to commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed-upon cost allocation will be put before the Commission for approval. As discussed

[1658] *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515.

[1659] *Supra* Categories of Factors section.

[1660] Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126, 268, 1293, 1362–1364, 1404, 1407, 1410–1411, 1415, 1477, 1515.

[1661] *Id.* P 227.

[1662] We believe that these findings address NESCOE's arguments that Order No. 1920's cost allocation requirements "[r]elegat[ed] states to commenting on a transmission provider's cost allocation filing," or that the "only path the Commission envision[ed] for approval of the states' cost allocation method would be through the vehicle of a complaint." NESCOE Rehearing Request at 14.

[1663] *See infra* Consultation with Relevant State Entities After the Engagement Period section.

[1664] Harvard ELI Rehearing Request at 1–3. Because we are unpersuaded by Harvard ELI's request for rehearing in this respect, we find it unnecessary to address Harvard ELI's request for clarification in the alternative that FPA section 206 provides the Commission the authority to amend the *pro forma* OATT to include a process for filing all cost allocation methods approved by Relevant State Entities. *Id.* at 8.

[1665] NARUC Rehearing Request at 21–22.

[1666] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 996 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 153), 1363; *see also* Order No. 890, 118 FERC ¶ 61,119 at P 454 ("[T]ransmission planning is the tariff obligation of each transmission provider."). To the extent that West Virginia Commission, in stating that the Commission should "grant the States 205 filing rights as it pertains to State-agreed cost allocations," is requesting that the Commission confer filing rights to states under FPA section 205, West Virginia Commission does not explain the authority or legal theory upon which it believes the Commission could do so. West Virginia Commission Rehearing Request at 14.

[1667] Harvard ELI Rehearing Request at 6–7.

[1668] *See* Design and Operation of the Engagement Period section.

[1669] Order No. 1920, 187 FERC ¶ 61,068 at P 126.

[1670] *See supra* P 654; *infra* Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

[1671] PIOs Rehearing Request at 55–56.

[1672] NESCOE Rehearing Request at 15–16.

[1673] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1412 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.").

further below, such a process could satisfy the requirement we establish for transmission providers to consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.[1674]

C. Design and Operation of the Engagement Period

1. Logical Outgrowth

a. NOPR Proposals

663. To implement the NOPR proposal to require transmission providers to include in their OATTs either a Long-Term Regional Transmission Cost Allocation Method or a State Agreement Process, or a combination thereof, the Commission proposed to require transmission providers to ''seek the agreement'' of relevant state entities regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning and to revise their OATTs to include the method or methods.[1675] The Commission additionally proposed to afford transmission providers flexibility in the process by which they seek agreement from the Relevant State Entities.[1676] The Commission stated that the proposed reforms would enable Relevant State Entities who seek greater involvement in cost allocation for Long-Term Regional Transmission Facilities an opportunity to do so.[1677]

664. In the NOPR, the Commission also proposed to require transmission providers to establish a process, detailed in their OATTs, to provide a state or states (in multi-state transmission planning regions) a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method that would otherwise apply. The Commission proposed that, during that time period, if a state or all states within the transmission planning region in which the selected regional transmission facility would be located unanimously agree on an alternate cost allocation method, the transmission provider may elect to file it with the Commission.[1678] The Commission explained that providing states with a time period to propose alternate cost allocation methods could help facilitate the timely development of more efficient or cost-effective regional transmission facilities.[1679]

b. Order No. 1920 Requirements

665. In Order No. 1920, the Commission declined to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities regarding the cost allocation method to be applied to Long-Term Regional Transmission Facilities.[1680] Instead, the Commission established a six-month Engagement Period, during which transmission providers must, among other things, provide a forum for the negotiation of a Long-Term Regional Transmission Cost Allocation Methods(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities, and required transmission providers to explain on compliance how they complied with the six-month Engagement Period requirements.[1681] The Commission also declined to adopt the NOPR proposal to require transmission providers to establish a process, detailed in their OATTs, to provide a state or states (in multi-state transmission planning regions) a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method that would otherwise apply.[1682]

c. Requests for Rehearing and Clarification

666. NRECA asserts that the requirement in Order No. 1920 for transmission providers to file a Long-Term Regional Transmission Cost Allocation Method with or without the agreement of Relevant State Entities, and to conduct a six-month Engagement Period to provide a forum for negotiation of Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process, is not a logical outgrowth of the NOPR proposal to require the transmission providers in a transmission planning region to seek agreement with Relevant State Entities as to a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process.[1683] Undersigned States argue that the NOPR ''placed the states in a central role in the regulatory structure by requiring transmission providers to seek the agreement of states for cost allocation,'' but that Order No. 1920 ''removed the requirement that states give their consent on cost allocation,'' which is '''surprisingly distant' from the states' role in the NOPR and is in essence a new rule that requires new opportunities for comment and input.''[1684] West Virginia Commission argues that Order No. 1920 ''effectively exceeds the substantive notice of the NOPR'' by removing realistic opportunities for states to work cooperatively on cost allocation agreements that will be proposed as *ex ante* cost allocation methods and adding ''an ineffective substitute for seeking state agreement for cost allocation'' by establishing the six-month Engagement Period.[1685] Utah Commission similarly contends that the elimination of any requirement that a state agree to a cost allocation that its residents must bear, no matter how detached the states' residents are from causing the associated costs or from the associated policies, does not constitute a logical outgrowth of the NOPR.[1686]

d. Commission Determination

667. As discussed elsewhere in this rule, we take steps in this order to expand Relevant State Entities' opportunities to inform and, as needed, provide alternatives to, transmission providers' proposed Long-Term Regional Transmission Cost Allocation Method(s). Therefore, while we disagree with rehearing parties' arguments that the Engagement Period and associated reforms are not a logical outgrowth of the NOPR, we note that certain modifications in this order address, at least in part, concerns that Order No. 1920 diminished the role of states in contrast to the NOPR.[1687]

668. In the NOPR, the Commission proposed to require transmission

[1674] *See Infra* Consultation with Relevant State Entities After the Engagement Period section.

[1675] NOPR, 179 FERC ¶ 61,028 at PP 278, 303, 305, 308.

[1676] *Id.* P 306.

[1677] *Id.* P 314.

[1678] *Id.* P 319.

[1679] *Id.* P 321.

[1680] Order No. 1920, 187 FERC ¶ 61,068 at P 1354.

[1681] *Id.* PP 1354, 1357.

[1682] *Id.* P 1456.

[1683] NRECA Rehearing Request at 17–18.

[1684] Undersigned States Rehearing Request at 38 (quoting *Int'l Union, United Mine Workers of Am.*, 407 F.3d at 1259–60).

[1685] West Virginia Commission Rehearing Request at 3.

[1686] Utah Commission Rehearing Request at 11–12.

[1687] *See supra* Requirement Concerning Relevant State Entities' Preferred Cost Allocation Methods section; *infra* Duration of the Engagement Period section; Consultation with Relevant State Entities After the Engagement Period section.

providers to ''seek the agreement'' [1688] of Relevant State Entities based upon its finding that ''providing state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning could help increase . . . state[ ] support for those facilities,'' [1689] thereby framing such a formal opportunity for state regulators as the subject for commenter discussion.[1690] Although Order No. 1920 did not adopt the proposed requirement to ''seek the agreement'' of Relevant State Entities, the Commission adopted a materially similar requirement—the Engagement Period—for transmission providers to provide, over a six-month period, a forum for negotiation of cost allocation methods for Long-Term Regional Transmission Facilities that enables meaningful participation by Relevant State Entities.[1691] The Engagement Period ''provide[s] state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning,'' precisely as contemplated in the NOPR.[1692] Indeed, as the Commission explained in Order No. 1920, ''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.'' [1693] The Engagement Period, which facilitates the meaningful involvement of Relevant State Entities in determining cost allocation methods for selected Long-Term Regional Transmission Facilities, is in character with, and consequently a logical outgrowth of, the proposal to require transmission providers to ''seek the agreement'' of Relevant State Entities for the applicable cost allocation method for selected transmission facilities.[1694]

2. Requests Arguing the Engagement Period Is Inferior to a Requirement That Transmission Providers Seek the Agreement of Relevant State Entities

a. Order No. 1920 Requirements

669. In Order No. 1920, the Commission established a six-month 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.[1695]

b. Requests for Rehearing and Clarification

670. Virginia and North Carolina Commissions and West Virginia Commission request rehearing of Order No. 1920's decision to not 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.[1696] West Virginia Commission argues that the Engagement Period is an ineffective substitute for 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.[1697] Virginia and North Carolina Commissions argue that, to provide the robust engagement required by Order No. 1920, the Commission should specify and bolster transmission providers' requirements to meaningfully engage with and proactively seek (but not necessarily obtain) the agreement of Relevant State Entities concerning cost allocation issues during the Engagement Period.[1698]

c. Commission Determination

671. As discussed in Order No. 1920 and reiterated in this order, it is critical to the success of the Long-Term Regional Transmission Planning reforms that states have an opportunity to have a significant role in the establishment of just and reasonable Long-Term Regional Transmission Cost Allocation Methods and State Agreement Processes. While we are unpersuaded by arguments that the Commission erred in declining 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 and instead establishing the Engagement Period,[1699] we believe that the requirements related to the Engagement Period, discussed below, that we adopt herein address the concerns underlying those rehearing requests.

672. In Order No. 1920, the Commission carefully weighed the appropriate level of transmission providers' engagement with Relevant State Entities regarding the cost allocation method to be applied to Long-Term Regional Transmission Facilities by considering the potential challenges inherent in such engagement. Specifically, the Commission found that while ''states play a critical role in transmission planning'' and ''facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings,'' mandating that transmission providers seek the agreement of Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) would present potential difficulties that counseled against adoption of this proposed reform.[1700] For example, the Commission considered the possibility that requiring transmission providers to seek the agreement of Relevant State Entities might create disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans.[1701] The

[1688] NOPR, 179 FERC ¶ 61,028 at PP 278, 303, 305, 308.

[1689] *Id.* P 299.

[1690] *Conn. Light & Power Co.* v. *Nuclear Regul. Comm'n,* 673 F.2d at 533 (holding that an agency's proposed rule must ''adequately frame the subjects for discussion'').

[1691] Order No. 1920, 187 FERC ¶ 61,068 at PP 1354, 1357.

[1692] *See* NOPR, 179 FERC ¶ 61,028 at P 299.

[1693] Order No. 1920, 187 FERC ¶ 61,068 at P 1362.

[1694] *See, e.g., Am. Paper Inst.* v. *EPA,* 660 F.2d at 959 n.13 (''An agency may make even substantial changes in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.''); *accord Chocolate Mfrs. Ass'n of U.S.* v. *Block,* 755 F.2d 1098, 1105 (4th Cir. 1985).

[1695] Order No. 1920, 187 FERC ¶ 61,068 at P 1354.

[1696] West Virginia Commission Rehearing Request at 8; Virginia and North Carolina Commissions Rehearing Request at 8–10.

[1697] West Virginia Commission Rehearing Request at 8.

[1698] Virginia and North Carolina Commissions Rehearing Request at 9–10.

[1699] West Virginia Commission Rehearing Request at 8; Virginia and North Carolina Commissions Rehearing Request at 8–10.

[1700] Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 1362.

[1701] *See id.* P 1362 & n.2906 (citing Minnesota State Entities NOPR Initial Comments).

Commission also considered the challenges of adopting a definition for "agreement" that would be necessary under a requirement for transmission providers to seek the agreement of Relevant States Entities.[1702]

673. We continue to find, as stated above, that states "play a critical role in transmission planning" and "facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings," [1703] and we find that establishing an Engagement Period recognizes that critical role while reducing the potential practical challenges discussed above, as compared to requiring transmission providers to seek the agreement of Relevant State Entities.[1704] We also continue to find that the 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.[1705] Beyond that, the modification we make here, to require transmission providers to submit any cost allocation methods agreed to by Relevant State Entities in the transmittal or as an attachment to their compliance filings, addresses the same concern and provides Relevant State Entities with additional means to demonstrate to the Commission any preferences around the cost allocation of Long-Term Regional Transmission Facilities. We therefore are unpersuaded by arguments raised by West Virginia Commission on rehearing that the Engagement Period is "ineffective" compared to the NOPR proposal.[1706] Similarly, with respect to Virginia and North Carolina Commissions' request that the Commission require transmission providers to "proactively seek" the agreement of Relevant State Entities to the transmission providers' preferred Long-Term Regional Transmission Cost Allocation Method,[1707] we find that Order No. 1920, as modified on rehearing, provides more opportunities for state engagement than a requirement to simply seek agreement with states for a Long-Term Regional Transmission Cost Allocation Method. Specifically, transmission providers must (1) provide the opportunity for Relevant State Entities from all states in a transmission planning region to participate in the Engagement Period; [1708] (2) upon the request of Relevant State Entities, facilitate and participate in a cost allocation discussion during the Engagement Period with Relevant State Entities; [1709] and (3) include, in the transmittal or as an attachment to their compliance filings, any Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process agreed to by Relevant State Entities.[1710]

3. Duration of the Engagement Period

a. Order No. 1920 Requirements

674. In Order No. 1920, the Commission found that limiting the Engagement Period to six months was necessary to ensure that transmission providers have sufficient time to prepare their compliance filings in advance of the compliance deadlines established in Order No. 1920.[1711]

b. Requests for Rehearing and Clarification

675. Several rehearing parties request extension of the Engagement Period.[1712] PJM States and Pennsylvania Commission request that the Commission clarify that the six-month Engagement Period will be extended for up to 12 months if states file a unanimous declaration that they are engaged in, but require additional time to complete, cost allocation discussions.[1713] West Virginia Commission requests that the Commission extend the Engagement Period to a minimum of 12 months or, in the alternative, authorize the extension of the Engagement Period if Relevant State Entities submit a declaration stating that they are continuing to engage in cost allocation discussions.[1714] SERTP Sponsors request that the Commission clarify that, upon unanimous consent of all affected state commissions (and the governing authorities for non-jurisdictional transmission providers), the Commission will allow (or, at a minimum, consider good-cause motions for) an extension of time for the development of *ex ante* state agreements to provide those entities with additional time to negotiate during the Engagement Period.[1715] PJM States, Pennsylvania Commission, and West Virginia Commission argue that the Commission should permit an extension of the Engagement Period because there are a large number of Relevant State Entities in PJM, there are highly diverse regulatory models used in those Relevant State Entities in PJM, and there are a wide variety of state laws and procedures applicable to those Relevant State Entities.[1716] Virginia and North Carolina Commissions argue that it would likely be beneficial to afford transmission providers greater flexibility with respect to the "timeline" of the Engagement Period, to the extent this flexibility would facilitate productive engagement with states without unduly delaying or impeding Order No. 1920's other requirements.[1717]

676. Wyoming Commission asserts that providing states with six months "to reach agreement with the default cost allocation looming is an illusory acknowledgement of state authority." [1718] Arizona Commission states that "the provision for states to negotiate acceptable cost allocations among them is limited to six months" and that "[s]ix months is not enough time for the states to establish rate cases." [1719] Designated Retail Regulators and Undersigned States argue that "reaching an agreement in MISO within the six-month window" may be difficult given states' different goals and agendas,[1720] and that six months is an insufficient amount of time to provide the due process required to approve any State Agreement Process.[1721]

[1702] *Id.* P 1361 (discussing commenter arguments that the Commission adopt different criteria for "agreement," including a majority, a threshold of one-half of the participating Relevant State Entities, or unanimity).

[1703] *Id.* PP 124, 1362.

[1704] *Id.* P 1362.

[1705] *Id.*

[1706] West Virginia Commission Rehearing Request at 8.

[1707] Virginia and North Carolina Commissions Rehearing Request at 10.

[1708] *See infra* Content of the Engagement Period section.

[1709] *See supra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1710] *See supra* Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1711] Order No. 1920, 187 FERC ¶ 61,068 at P 1358.

[1712] PJM States Rehearing Request at 3–4; Pennsylvania Commission Rehearing Request at 1 (adopting PJM States' arguments); West Virginia Commission Rehearing Request at 13; SERTP Sponsors Rehearing Request at 7–8; Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

[1713] PJM States Rehearing Request at 3–4; Pennsylvania Commission Rehearing Request at 1.

[1714] West Virginia Commission Rehearing Request at 13.

[1715] SERTP Sponsors Rehearing Request at 7–8.

[1716] PJM States Rehearing Request at 3; Pennsylvania Commission Rehearing Request at 1; West Virginia Commission Rehearing Request at 13.

[1717] Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

[1718] Wyoming Commission Rehearing Request at 7.

[1719] Arizona Commission Rehearing Request at 17 n.14.

[1720] Designated Retail Regulators Rehearing Request at 35; Undersigned States Rehearing Request at 31.

[1721] Designated Retail Regulators Rehearing Request at 9; Undersigned States Rehearing Request at 9.

c. Commission Determination

677. We set aside, in part, Order No. 1920's requirements on the duration of the Engagement Period. In Order No. 1920, the Commission noted 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.[1722] Moreover, the Commission found that facilitating state involvement in the regional cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.[1723] In keeping with these findings, and upon further consideration, we find that extending the Engagement Period may be appropriate when Relevant State Entities represent to the Commission that they need additional time to complete cost allocation discussions.

678. Providing the opportunity for such an extension is consistent with the critical role that states play in addressing these issues and ensuring that they have the time necessary to adequately engage in these issues. Therefore, in response to arguments raised by PJM States, Pennsylvania Commission, and West Virginia Commission, we set aside Order No. 1920's requirements, in part, to specify that the Commission will grant an extension of the required Engagement Period for up to an additional six months when Relevant State Entities, consistent with their chosen method to reach agreement, request additional time to complete cost allocation discussions. We find that such an extension is warranted in that circumstance to ensure that Relevant State Entities have sufficient time to engage in fulsome discussions. We also clarify that in such circumstances, the Commission will also, as appropriate, extend, *sua sponte,* the relevant Order No. 1920 compliance deadlines to accommodate an extension of the Engagement Period and to ensure that any such extension would not conflict with the required compliance deadlines.

4. Content of the Engagement Period

a. Order No. 1920 Requirements

679. In Order No. 1920, the Commission required the transmission providers in each transmission planning region to provide notice, such as on their OASIS pages or public websites, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period. The Commission required that such notice 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, which must be no earlier than the end date of the Engagement Period.[1724] The Commission also required 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.[1725]

680. The Commission required that transmission providers 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.[1726]

681. The Commission declined 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, or to establish a minimum set of criteria for a state agreement. Instead, the Commission left such matters, including whether to use existing state processes as a forum for negotiations, to the Relevant State Entities participating in the Engagement Period to determine.[1727] The Commission also declined to expand participation in the Engagement Period beyond Relevant State Entities, stating that it did not find it necessary to allow other stakeholders to participate in the Engagement Period.[1728]

b. Requests for Rehearing and Clarification

682. PJM States and NARUC request that the Commission require transmission providers to include in their compliance filings, at minimum, the setting and communicating of deadlines and the general forum for transmission provider discussions with and outreach to state entities concerning the Engagement Period.[1729] PJM States contend that these and other clarifications would demonstrate the extent to which transmission providers engaged with states during the Engagement Period.[1730]

683. PJM States request clarification that the Engagement Period is actually a ''State Engagement Period'' and that ''states are *the* stakeholder(s) to engage.'' [1731] PJM States explain that any such clarification should not prohibit states from inviting other entities that might be helpful in assisting states in reaching agreement on cost allocation. Rather, PJM States argue that the Commission should make clear that the Engagement Period is ''not for the engagement of all stakeholders'' but is instead intended to provide a forum for transmission providers and states to attempt to reach agreement on cost allocation.[1732]

c. Commission Determination

684. In response to the requests of PJM States and NARUC for clarification as to the information that transmission providers must include in their compliance filings concerning the Engagement Period,[1733] we clarify that, in order to comply with the requirement that transmission providers explain how they provided a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process during the Engagement Period that enables meaningful participation by Relevant State Entities,[1734] transmission providers must at minimum disclose any deadlines set by transmission providers during the Engagement Period and how transmission providers communicated any such deadlines to Relevant State Entities, and provide a general description of the forum for negotiation.[1735]

[1722] Order No. 1920, 187 FERC ¶ 61,068 at P 124.

[1723] *Id.*

[1724] *Id.* P 1356. The Commission noted Relevant State Entities must indicate that they have agreed to any State Agreement Process for any such process to be eligible for acceptance by the Commission in compliance with Order No. 1920. *Id.* P 1356 n.2895.

[1725] *Id.* P 1357.

[1726] *Id.*

[1727] *Id.* PP 1360–1361 (citations omitted).

[1728] *Id.* P 1363.

[1729] NARUC Rehearing Request at 17; PJM States Rehearing Request at 7.

[1730] PJM States Rehearing Request at 8.

[1731] *Id.* (emphasis in original).

[1732] *Id.* at 8–9.

[1733] *See id.* at 7; NARUC Rehearing Request at 17–18.

[1734] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1357.

[1735] We address the requests of PJM States, NARUC, and other parties that the Commission require transmission providers to include additional information related to the Engagement Period in their compliance filings—such as requests that the Commission require each transmission provider to include states' preferred cost allocation

Continued

685. With respect to PJM States' argument that the Commission should clarify that the Engagement Period is ''not for the engagement of all stakeholders,'' [1736] we reiterate that the Commission declined to expand participation in the Engagement Period beyond Relevant State Entities, and did not find it necessary to allow other stakeholders to participate in the Engagement Period.[1737] However, we also reiterate that the Commission allowed Relevant State Entities to permit the participation of other entities subsequently during implementations of a State Agreement Process.[1738] We also reiterate our determination in Order No. 1920 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 region, including any state entity as may be designated for that purpose by the law of such state,[1739] and we continue to find that this definition recognizes the important role of states while providing sufficient regional flexibility for effective Engagement Period participation.[1740]

686. With respect to PJM States' request for clarification that the Engagement Period is actually a ''State Engagement Period'' and that the states are the stakeholders with which transmission providers must engage during the Engagement Period,[1741] we grant clarification, in part, and clarify that transmission providers must provide the opportunity for Relevant State Entities from all states in each transmission planning region to participate in the Engagement Period.

5. Consultation With Relevant State Entities After the Engagement Period

a. Order No. 1920 Requirements

687. In Order No. 1920, the Commission declined to require future Engagement Periods, but noted that transmission providers may hold future Engagement Periods if they believe that such periods would be beneficial.[1742]

b. Requests for Rehearing and Clarification

688. NARUC and NESCOE request rehearing of Order No. 1920's decision not to require future Engagement Periods.[1743] NESCOE argues that following the initial Engagement Period, any proposed modification to the transmission planning region's Long-Term Regional Transmission Cost Allocation Method should trigger an obligation to establish a new Engagement Period to provide a forum for Relevant State Entities to discuss the proposed Long-Term Regional Transmission Cost Allocation Method. NESCOE explains that absent this obligation, a transmission provider could undo the efforts of Relevant State Entities in agreeing to a Long-Term Regional Transmission Cost Allocation Method during the initial Engagement Period by filing a new Long-Term Regional Transmission Cost Allocation Method without consulting with Relevant State Entities.[1744]

689. NARUC requests that the Commission create a mechanism that ensures regular re-examination of the Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process in a transmission provider's OATT. Specifically, NARUC argues that the Commission should require each transmission provider to periodically open a new negotiation period with Relevant State Entities.[1745]

690. Virginia and North Carolina Commissions argue that it would likely be beneficial to afford transmission providers greater flexibility with respect to the ''frequency'' of the Engagement Period, to the extent this flexibility would facilitate productive engagement with states without unduly delaying or impeding Order No. 1920's other requirements.[1746]

c. Commission Determination

691. We are persuaded by NARUC's and NESCOE's arguments raised on rehearing. Accordingly, we set aside Order No. 1920, in part, and require that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process. The consultation requirement will provide a mechanism through which transmission providers and Relevant State Entities can engage regarding possible future changes via FPA section 205 to cost allocation methods accepted by the Commission in compliance with Order No. 1920.[1747] We require transmission providers to include in their OATTs a description of how they will consult with Relevant State Entities in these circumstances. Additionally, for a consultation initiated by the transmission providers, we require transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment. For a consultation initiated by Relevant State Entities, if the transmission providers choose not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) preferred by Relevant State Entities during the required consultation, we also require transmission providers to document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.

692. We find that these requirements will ensure that states have the opportunity to be involved in establishing cost allocation methods for Long-Term Regional Transmission Facilities subsequent to the Commission's acceptance of transmission providers' filings made in compliance with Order No. 1920, which has the potential to minimize additional costs and delays in the siting process and to facilitate the development of Long-Term Regional Transmission

method in its compliance filing above in the Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section.

[1736] PJM States Rehearing Request at 8–9.

[1737] Order No. 1920, 187 FERC ¶ 61,068 at P 1363.

[1738] *Id.* P 1402.

[1739] *Id.* P 1355.

[1740] *Id.* P 1364.

[1741] PJM States Rehearing Request at 8.

[1742] Order No. 1920, 187 FERC ¶ 61,068 at P 1368.

[1743] NARUC Rehearing Request at 21–22; NESCOE Rehearing Request at 13–14.

[1744] NESCOE Rehearing Request at 13–14 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 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, consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO.'' (citations omitted))).

[1745] NARUC Rehearing Request at 21–22. In the Requirements Concerning Relevant State Entities' Preferred Cost Allocation Methods section above, we discuss NARUC's alternative request that the Commission require each transmission provider to file a modification to its OATT if states reach the requisite agreement on a different cost allocation method than that reflected in its OATT.

[1746] Virginia and North Carolina Commissions Rehearing Request at 11 n.27.

[1747] We clarify that this consultation requirement neither requires transmission providers to submit, nor prohibits transmission providers from submitting, FPA section 205 filings to modify cost allocation methods accepted in compliance with Order No. 1920, and transmission providers therefore retain their currently effective FPA section 205 rights. That said, as noted below, transmission providers may satisfy the consultation requirement by voluntarily agreeing to submit FPA section 205 proposals supported by Relevant State Entities. *Infra* P 692.

Facilities.[1748] While we provide transmission providers flexibility as to the form and duration of their required consultation with Relevant State Entities, we note that one way transmission providers could satisfy the requirement to consult with Relevant State Entities is by revising their OATTs to include a process under which the transmission provider must present to the Commission, in addition to its own FPA section 205 proposal, an alternative cost allocation method proposed by Relevant State Entities for evaluation by the Commission on equal footing.[1749] Transmission providers could also satisfy the requirement to consult with Relevant State Entities by revising their OATTs to include mechanisms similar to those used in SPP [1750] and MISO.[1751]

D. Design and Operation of State Agreement Processes

1. Definition of Relevant State Entities

a. Order No. 1920 Requirements

693. In Order No. 1920, the Commission defined 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 region, including any state entity as may be designated for that purpose by the law of such state. The Commission stated that it modified the NOPR proposal's definition to add the word "electric" before "utility regulation" in order to make clear that Relevant State Entities are those state agencies responsible for *electric* utility regulation, and not other types of utility regulation.[1752] In Order No. 1920, the Commission declined requests to expand or clarify the definition of Relevant State Entities and did not modify the definition beyond adding the word "electric," but permitted other participants beyond Relevant State Entities to participate in a State Agreement Process, if agreed to by Relevant State Entities.[1753]

b. Requests for Rehearing and Clarification

694. APPA contends that the Commission erred in excluding municipal electric regulatory bodies from the Relevant State Entity definition.[1754] APPA claims that excluding public power utilities and municipal governing bodies is arbitrary and capricious because: (1) the Commission failed to justify excluding customers served by municipal utilities during the Engagement Period, which is unduly discriminatory; [1755] (2) the Commission gave no meaningful rationale for excluding self-regulated public utilities from the Relevant State Entity definition, and inclusion would increase local support and reduce uncertainty and risk for development of Long-Term Regional Transmission Facilities; and (3) the definition of Relevant State Entity conflicts with the FPA's definition of "state commission" as "the regulatory body of the State or *municipality* having jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State or *municipality*." [1756]

695. Large Public Power claims that non-jurisdictional self-regulating non-public utilities under FPA section 201(f) could be profoundly affected by the Engagement Period without representation, and their exclusion from the definition of Relevant State Entity is arbitrary and capricious.[1757] Large Public Power states that its members are self-regulating entities that possess many of the same regulatory characteristics as state commissions, undertake retail ratemaking publicly, are not represented by state commissions, and in some states represent a market share larger than most individual investor-owned utilities.[1758] Large Public Power states that the FPA explicitly recognizes political subdivisions' authority through exemptions.[1759] Large Public Power argues that the Commission should provide an opportunity for municipal utilities to have a voice equal to that of state utility commissions to ensure that Long-Term Regional Transmission Facilities are not built and paid for by their customers unless such facilities are needed and wanted.[1760] Large Public Power states that the most obvious solution to this issue would be to grant municipal utilities representation on a load ratio share basis.[1761]

696. City of New Orleans Council requests clarification to confirm that it meets the definition of a Relevant State Entity.[1762] City of New Orleans Council states that it is designated and recognized by the State of Louisiana and the Home Rule Charter of the City of New Orleans as the governmental body that supervises, regulates, and controls public utilities within New Orleans.[1763] City of New Orleans Council states that MISO recognizes the City of New Orleans Council's unique regulatory authority and status.[1764] Noting that Order No. 1920 refers to OMS as an existing mechanism for state involvement, City of New Orleans Council states that it is a member of OMS that represents the collective interests of its members, which are state and local regulators within MISO's footprint.[1765] City of New Orleans Council states that it is also a member of the Entergy Regional State Committee (ERSC), which is comprised of retail regulators from the MISO-South subregion and recognized in MISO stakeholder forums, and that the ERSC bylaws recognize that the City of New Orleans Council is included as a "state regulatory agency." [1766] City of New Orleans Council also argues that its recognition within MISO is consistent with PJM's recognition of the District of Columbia.[1767]

697. City of New Orleans Council requests rehearing in the event that the Commission does not grant its request

[1748] *E.g.,* Order No. 1920, 187 FERC ¶ 61,068 at PP 124, 126.

[1749] *See, e.g.,* ISO New England Inc., FERC FPA Electric Tariff, ISO New England Inc. Agreements and Contracts, TOA, Transmission Operating Agreement (5.0.0), 3.04(h)(vi)(C); *see also The Governors of Conn., Me., Mass., N.H., R.I., Vt.,* 112 FERC ¶ 61,049, at P 25 (2005).

[1750] SPP, Governing Documents Tariff, Bylaws, First Revised Volume No. 4 (0.0.0), 7.2 (Regional State Committee) (providing that the Regional State Committee has primary responsibility for determining regional proposals regarding, among other things, "whether license plate or postage stamp rates will be used for the regional access charge," and that when the Regional State Committee "reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the [FPA]"); *see also Sw. Power Pool, Inc.,* 106 FERC ¶ 61,110, at PP 218–220, *order on reh'g,* 109 FERC ¶ 61,010, at PP 92–94 (2004); *Sw. Power Pool, Inc.,* 108 FERC ¶ 61,003, at P 127 & n.90 (2004), *order on reh'g,* 110 FERC ¶ 61,138, at P 33 (2005).

[1751] MISO FERC Electric Tariff, MISO Rate Schedules, MISO Transmission Owner Agreement, app. K (Filing Rights Pursuant To Section 205 Of The FPA) (3.0.0), II.E.3.a.i–ii (providing the circumstances under which the OMS Committee "shall have the right to request and MISO shall file for a new or an amendment of any regional cost allocation methodology"); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 143 FERC ¶ 61,165, at PP 30, 32 (2013).

[1752] Order No. 1920, 187 FERC ¶ 61,068 at P 1355.

[1753] *Id.* PP 1364 & n.2914, 1402.

[1754] APPA Rehearing Request at 2.

[1755] *Id.* at 4.

[1756] *Id.* at 5 (citing 16 U.S.C. 796(15)) (emphasis in original).

[1757] Large Public Power Rehearing Request at 11.

[1758] *Id.*

[1759] *Id.* at 12.

[1760] *Id.* at 12–13.

[1761] *Id.* at 13.

[1762] City of New Orleans Council Rehearing Request at 4.

[1763] *Id.* (citing La. Const., art. IV, § 21(c); Home Rule Charter of the City of New Orleans, § 3–130).

[1764] *Id.* at 5.

[1765] *Id.* (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1357).

[1766] *Id.* at 6 (citing Entergy Regional State Committee (ERSC), *https://www.misoenergy.org/engage/committees/entergy-regional-state-committee/* (ERSC Mission Statement); ERSC Bylaws, *https://cdn.misoenergy.org/ERSC%20Bylaws%20(Amended%202%2014%2022)%20217600.pdf* (amended Feb. 14, 2022)).

[1767] *Id.* at 6–7.

for clarification, noting that the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans recognize City of New Orleans Council's status as the governmental body with the power of supervision, regulation, and control over public utilities, and noting MISO's recognition of the City of New Orleans Council's status.[1768] City of New Orleans Council states that finding that it does not meet the definition of Relevant State Entity would be contrary to such legal and regulatory recognition.[1769]

698. NESCOE requests that the Commission clarify that Regional State Committees are included in the definition of Relevant State Entities, or in the alternative, NESCOE seeks rehearing.[1770] NESCOE states that it is unclear that Regional State Committees, such as NESCOE, which do not necessarily appear in state laws and are not necessarily state agencies, are Relevant State Entities.[1771] NESCOE states that it appears that the Commission did not deliberately exclude Regional State Committees from the definition of Relevant State Entities, but that the Commission appears to have misapprehended NESCOE's argument in its comments as solely concerned about its unique structure of achieving consensus among the New England states.[1772]

699. NRECA states that, even following its comments to the NOPR, the definition of Relevant State Entity excludes cooperatives and public power utilities not subject to regulation by a state utility commission and the Engagement Period includes only Relevant State Entities. NRECA argues that, as a result, Order No. 1920 allows a Relevant State Entity to dictate cost allocation to electric utilities it does not regulate.[1773]

c. Commission Determination

700. We deny the requests for clarification and disagree with APPA's and Large Public Power's requests for rehearing asking to expand the definition of Relevant State Entity.[1774] As discussed in Order No. 1920, we continue to find that ''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.''[1775]

701. Municipal electric regulatory bodies and non-public utility entities provide valuable insight as stakeholders in Commission-sanctioned processes. But in defining Relevant State Entities for the purposes of Order No. 1920, we find that state entities responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region are, as discussed above, uniquely situated to influence whether or not a Long-Term Regional Transmission Facility reaches completion. On balance, while we recognize the important role that other stakeholders play in Long-Term Regional Transmission Planning, we continue to find that the definition of Relevant State Entities should encompass only any state entities 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.[1776] In Order No. 1920, the Commission further stated, and we continue to believe, that:

> [P]roviding 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.[1777]

702. For the same reasons, we also do not find it necessary to expand the definition of Relevant State Entities for the purposes of Order No. 1920.

703. In response to City of New Orleans Council's and NESCOE's requests,[1778] we will not make a finding on whether an individual state's laws, regulations, and/or policies, or inclusion in a larger association of regulators, deem a certain entity to be a Relevant State Entity, though we note that state law may be a persuasive or dispositive factor in such determinations.[1779] Instead, entities within a state must determine if they qualify as Relevant State Entities based on the definition the Commission provided in Order No. 1920 and based upon their interpretation of their state laws. We also reiterate that Order No. 1920 permits other participants, including municipal electric regulatory bodies and non-public utility entities that do not otherwise meet the definition of a Relevant State Entity, to participate in a State Agreement Process, if agreed to by Relevant State Entities.[1780] Finally, we disagree with NRECA's assertion that Order No. 1920 permits Relevant State Entities to dictate cost allocation to utilities they do not regulate.[1781] Order No. 1920, as modified here on rehearing, provides robust opportunities for Relevant State Entities to participate in the development of Long-Term Regional Transmission Cost Allocation Methods, given the critical role that states will play in the success of Long-Term Regional Transmission Planning. However, it is ultimately the Commission that will determine whether cost allocation methods proposed on compliance are just and reasonable and not unduly discriminatory or preferential, and all interested parties will have a full and fair opportunity to participate both in regional stakeholder proceedings and in compliance proceedings before the Commission.

704. In response to APPA's contention that the definition of Relevant State Entity conflicts with the FPA's definition of ''state commission'' as ''the regulatory body of the State or *municipality* having jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State or *municipality,*''[1782] we find that the definition of Relevant State Entity for purposes of Long-Term Regional Transmission Facility cost allocation is distinct from the purpose of the definition of ''state commission'' in the

[1768] *Id.* at 8.

[1769] *Id.* at 9.

[1770] NESCOE Rehearing Request at 17–20.

[1771] *Id.* at 18–19.

[1772] *Id.* at 19.

[1773] NRECA Rehearing Request at 57–58.

[1774] APPA Rehearing Request at 2, 4–5; Large Public Power Rehearing Request at 11–13.

[1775] Order No. 1920, 187 FERC ¶ 61,068 at P 1364 (quoting NOPR, 179 FERC ¶ 61,028 at P 297 (footnote omitted)).

[1776] As noted below, we make no findings here regarding whether any individual municipal electric regulatory body or non-public utility entity meets the definition of a Relevant State Entity, as those determinations properly rest with entities in a state, based upon their interpretation of their state laws. *Infra* P 703.

[1777] Order No. 1920, 187 FERC ¶ 61,068 at P 1364 (alterations omitted) (citing NOPR, 179 FERC ¶ 61,028 at P 299).

[1778] City of New Orleans Council Rehearing Request at 4, 8; NESCOE Rehearing Request at 17–20.

[1779] Order No. 1920 also allows Relevant State Entities to participate in cost allocation negotiations through a regional body. *See, e.g.,* Order No. 1920, 187 FERC ¶ 61,068 at P 999 (declining to impose specific requirements regarding how consultation with Relevant State Entities will occur, and recognizing need for flexibility ''based on the specific needs and makeup of their transmission planning region'').

[1780] *Id.* PP 1364 & n.2914, 1402.

[1781] NRECA Rehearing Request at 57–58.

[1782] APPA Rehearing Request at 5 (citing 16 U.S.C. 796(15)) (emphasis in original).

FPA and need not align with it. We note, for example, that the FPA defines ''state commission'' and ''state'' separately, and in the final rule we use neither of these two definitions.[1783]

2. Extensions of Time for Negotiation of Cost Allocation Methods Under State Agreement Processes

a. Order No. 1920 Requirements

705. In Order No. 1920, the Commission required that any State Agreement Process 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).[1784] The Commission found 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 the Commission required transmission providers to include in their OATTs, that the lack of such a deadline could cause delay and increase uncertainty regarding selected Long-Term Regional Transmission Facilities, and 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.[1785] The Commission found 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.[1786]

b. Requests for Rehearing and Clarification

706. Designated Retail Regulators and Undersigned States argue that the State Agreement Process is unreasonable because Order No. 1920 does not provide adequate time for the adoption of a cost allocation method that follows any approved State Agreement Process.[1787]

707. SERTP Sponsors request that the Commission clarify that upon unanimous consent of state commissions and relevant governing authorities for SERTP Sponsors not subject to the Commission's jurisdiction, the Commission will allow an extension of time for the development of methods resulting from a State Agreement Process.[1788] SERTP Sponsors request that at a minimum, the Commission clarify that it will consider motions for an extension of time for good cause.[1789]

c. Commission Determination

708. We believe that the six-month deadline by which transmission providers must file any cost allocation method that results from a State Agreement Process is reasonable and are thus unpersuaded by parties who challenge the sufficiency of this deadline. While we emphasize the benefits of a State Agreement Process, we continue to find that this deadline balances the need for adequate time for Relevant State Entities to conduct negotiations with the need for finality in Long-Term Regional Transmission Planning.[1790] Consistent with Order No. 1920, we find that a deadline, coupled with a default Long-Term Regional Transmission Cost Allocation Method, may encourage Relevant State Entities to timely reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.[1791] While we grant SERTP Sponsors' request to clarify that transmission providers may file motions for an extension of time for good cause to the State Agreement Process beyond six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities), we decline at this time to categorically pre-approve extensions (even if unanimous), and thus we deny SERTP Sponsors' associated request for clarification. Instead, the Commission will consider any such requests on the record before it at that time.

E. Use of Existing Cost Allocation Methods in Long-Term Regional Transmission Planning or Existing Regional Processes

1. Order No. 1920 Requirements

709. In Order No. 1920, the Commission required that, to the extent transmission providers believe that their existing cost allocation methods comply with the requirements of Order No. 1920, they may demonstrate in their compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of Order No. 1920.[1792] The Commission also required that transmission providers that wish to continue using existing 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.[1793]

2. Requests for Rehearing and Clarification

710. PJM requests that the Commission grant rehearing and confirm that it will consider requests to maintain existing cost allocation methods on compliance unless and until an alternative is filed.[1794] PJM argues that the Commission has not justified why Order No. 1920 ''categorically prohibit[s] existing cost allocation methodologies from remaining in place'' in such circumstances.[1795] PJM states that it is concerned that requiring transmission owners to re-justify existing cost allocation methods will set back efforts to implement its Long-Term Regional Transmission Planning Process.[1796] PJM argues that the requirement to renegotiate all cost allocation methods undercuts the longstanding and widely-accepted notion that knowing how costs for transmission facilities will be allocated is critical for their development.[1797] PJM further states that its existing cost allocation method includes specific cost allocations for reliability-based projects, market efficiency projects, public policy projects addressing state-identified needs, and multi-driver projects.[1798] PJM argues that requiring transmission owners to re-justify the existing cost allocation methods undermines the certainty regarding the development of transmission facilities PJM selects to be built.[1799] PJM states that its existing cost allocation methods are the result of years of close consultation and extensive work among the states in the PJM region and litigation before the Commission. PJM argues that Order No. 1920 effectively erases these efforts.[1800]

[1783] *See* 16 U.S.C. 796(15)) and 16 U.S.C. 796(6), respectively.

[1784] Order No. 1920, 187 FERC ¶ 61,068 at P 1406.

[1785] *Id.* P 1413.

[1786] *Id.* P 1414.

[1787] Designated Retail Regulators Rehearing Request at 9; Undersigned States Rehearing Request at 8.

[1788] SERTP Sponsors Rehearing Request at 7–8.

[1789] *Id.*

[1790] Order No. 1920, 187 FERC ¶ 61,068 at P 1414.

[1791] *Id.* P 1413.

[1792] *Id.* PP 1302–1303.

[1793] *Id.* P 243.

[1794] PJM Rehearing Request at 19–23.

[1795] *Id.* at 20.

[1796] *Id.* at 20–21.

[1797] *Id.* at 21 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 124).

[1798] *Id.* at 22–23.

[1799] *Id.* at 21.

[1800] *Id.* at 22–23.

711. Ohio Commission Federal Advocate asserts that Order No. 1920 arbitrarily and capriciously requires continued use of PJM's State Agreement Approach to be re-approved by the Commission. Specifically, Ohio Commission Federal Advocate argues that the State Agreement Approach has long been approved and used in the PJM region to ensure just and reasonable cost allocation for public policy projects and asks the Commission to revise Order No. 1920 to explicitly allow the continued use of the State Agreement Approach at least to the projects to which it currently applies.[1801]

3. Commission Determination

712. Upon consideration of the rehearing requests, we sustain Order No. 1920's requirement that transmission providers that wish to continue using existing 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. We similarly decline to set aside Order No. 1920's requirement that to use an existing cost allocation method as a Long-Term Regional Transmission Cost Allocation Method, a transmission provider must demonstrate in its compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, comply with Order No. 1920.

713. We disagree with PJM's request to continue to use existing regional cost allocation methods for Long-Term Regional Transmission Facilities without a showing that such use complies with the requirements of Order No. 1920.[1802] However, we note that Order No. 1920 does not prohibit transmission providers from proposing to use existing regional cost allocation methods to comply with the requirements for Long-Term Regional Transmission Cost Allocation Methods, so long as the transmission providers demonstrate that the existing methods are just and reasonable and not unduly discriminatory or preferential when applied to Long-Term Regional Transmission Facilities and comply with the requirements of Order No. 1920 and the cost causation principle.[1803] Nevertheless, given the deficiencies identified in existing transmission planning and cost allocation processes identified by the Commission in Order No. 1920 and the numerous reforms adopted in Order No. 1920 for Long-Term Regional Transmission Planning to address those deficiencies, it would be unjust and unreasonable for the Commission to accept existing cost allocation methods for Long-Term Regional Transmission Facilities without ensuring that such methods are consistent with Order No. 1920.[1804]

714. We recognize that it may be just and reasonable to apply existing regional cost allocation methods to Long-Term Regional Transmission Facilities for many of the same reasons that the Commission found these methods to be just and reasonable when initially approving them. For this reason, Order No. 1920 specifically provided that transmission providers may demonstrate in their compliance filings that their existing regional cost allocation methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of Order No. 1920.[1805] As such, we disagree with PJM's assertion that Order No. 1920 will ignore past efforts to facilitate consensus on cost allocation methods.[1806]

715. We disagree with Ohio Commission Federal Advocate's assertion that Order No. 1920 requires that the continued use of PJM's State Agreement Approach must be re-approved by the Commission and that the final rule limits use of PJM's State Agreement Approach.[1807] We note that Order No. 1920 requires reapproval for existing cost allocation methods' use in Long-Term Regional Transmission Planning only if those methods are to be used for compliance with Order No. 1920.[1808] PJM's State Agreement Approach is not a regional cost allocation method used to comply with the requirements of Order No. 1000. The Commission approved the existing PJM State Agreement Approach in an order on compliance in the Order No. 1000 proceeding, but did not find that the PJM State Agreement Approach was a regional cost allocation method compliant with the requirements of Order No. 1000.[1809] In addition, PJM's State Agreement Approach is different than the ''State Agreement Process'' as discussed in Order No. 1920. The State Agreement Process referenced in Order No. 1920 is a new construct under which Relevant State Entities may agree to a different cost allocation method for Long-Term Regional Transmission Facilities than the generally applicable Long-Term Regional Transmission Cost Allocation Method on file. Therefore, we clarify that Order No. 1920 does not prohibit PJM from maintaining its existing State Agreement Approach for transmission facilities that are not selected in either its Order No. 1000 regional transmission planning process or through Long-Term Regional Transmission Planning.[1810] To clarify further, PJM's State Agreement Approach is supplemental to PJM's existing regional transmission cost

[1801] Ohio Commission Federal Advocate Rehearing Request at 12–13.

[1802] PJM Rehearing Request at 19–23.

[1803] Order No. 1920, 187 FERC ¶ 61,068 at PP 1302–1303.

[1804] *Id.* PP 124–125 (citations omitted), 1302–1303 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 565; Order No. 1000–A, 139 FERC ¶ 61,132 at P 747).

[1805] *Id.* PP 1302–1303. In Order No. 1000, in response to ''concerns regarding relitigation of existing Commission-approved transmission cost allocation methods,'' the Commission declined ''to prejudge whether any such existing cost allocation methods compl[ied] with the requirements of [Order No. 1000],'' and noted that ''[t]o the extent [transmission providers] believe[d] that to be the case with their region, they [could] take such positions during the development of compliance proposals and during Commission review of compliance filings.'' Order No. 1000, 136 FERC ¶ 61,051 at P 565. On compliance, the Commission found that SPP's existing Balanced Portfolio and Highway/Byway regional cost allocation methods and MISO's existing regional cost allocation methods for Multi-Value Projects (MVPs) and Market Efficiency Projects (MEP) complied with the requirements of Order No. 1000. *Sw. Power Pool, Inc.,* 144 FERC ¶ 61,059, at PP 336, 347 (2013), *order on reh'g and compliance,* 149 FERC ¶ 61,048, at P 276 (2014), *order on reh'g and compliance,* 151 FERC ¶ 61,045, *order on compliance,* 152 FERC ¶ 61,106 (2015); *Midwest Indep. Transmission Sys. Operator, Inc.,* 142 FERC ¶ 61,215, at PP 420, 434 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,127, at P 404 (2014), *order on reh'g and compliance,* 150 FERC ¶ 61,037 (2015), *order on compliance,* Docket No. ER13–187–010 (Mar. 31, 2015) (delegated order).

[1806] PJM Rehearing Request at 22–23. With respect to PJM's request to continue using its existing regional cost allocation method for public policy projects addressing state-identified needs outside of Long-Term Regional Transmission Planning, we address this issue above in the Requirement to Participate in Long-Term Regional Transmission Planning section.

[1807] Ohio Commission Federal Advocate Rehearing Request at 12–13.

[1808] Order No. 1920, 187 FERC ¶ 61,068 at PP 1302–1303.

[1809] *See PJM Interconnection, L.L.C.* 142 FERC ¶ 61,214, at P 142 (2013) (''We find PJM's proposed State Agreement Approach is not needed for PJM to comply with the provisions of Order No. 1000 addressing transmission needs driven by public policy requirements. PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 addressed above. Accordingly, the Commission need not find that the State Agreement Approach and corresponding cost allocation method comply with Order No. 1000.''), *order on reh'g and compliance,* 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance,* 150 FERC ¶ 61,038, *order on reh'g and compliance,* 151 FERC ¶ 61,250 (2015).

[1810] *See supra* Requirement to Participate in Long-Term Regional Transmission Planning section (responding to Pennsylvania Commission's and PJM States' requests regarding the PJM State Agreement Approach).

allocation method and, as a result, is not in any way affected by Order No. 1920.

716. However, if the Relevant State Entities in PJM agree to rely on its existing PJM State Agreement Approach as an Order No. 1920 State Agreement Process that applies to selected Long-Term Regional Transmission Facilities, and if PJM agrees, PJM would have to propose and demonstrate on compliance that its State Agreement Approach complies with all of the State Agreement Process requirements set forth in Order No. 1920. In addition, we reiterate that the *ex ante* Long-Term Regional Transmission Cost Allocation Method(s) that Order No. 1920 prescribes would be used to allocate the costs of selected Long-Term Regional Transmission Facilities if any Order No. 1920-compliant State Agreement Process does not result in a cost allocation method within six months after a project is selected, as described in the final rule. As noted above, the Commission will consider the entire record—including the Relevant State Entities' agreed-upon Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and the transmission provider's proposal—when setting the replacement rate.

717. In addition, more generally, we clarify that we permit continued use of other existing state agreement approaches and similar voluntary measures under Order No. 1920, so long as they are consistent with the requirements stated above.

F. Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities

1. Logical Outgrowth

a. NOPR Proposals

718. In the NOPR, 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.[1811] The Commission made a preliminary finding that compliance with such principles will help ensure that Commission-jurisdictional rates resulting from any State Agreement Process will be just and reasonable and not unduly discriminatory or preferential.[1812] The six regional transmission cost allocation principles adopted in Order No. 1000 are: principle (1), the costs of 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; principle (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; principle (3), a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; principle (4), costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; principle (5), the method for determining benefits and identifying beneficiaries must be transparent; and principle (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.[1813]

b. Order No. 1920 Requirements

719. In Order No. 1920, the Commission adopted the NOPR proposal, with modification, to require compliance with Order No. 1000 regional cost allocation principles (1) through (5) for Long-Term Regional Transmission Cost Allocation Methods that transmission providers propose but to which Relevant State Entities have not indicated their agreement. The Commission explained that, because compliance with regional cost allocation principle (6) is not required, transmission providers cannot adopt different *ex ante* 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.[1814]

720. The Commission additionally determined that compliance with the Order No. 1000 regional cost allocation principles is not required in two situations: (1) Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed as part of the Engagement Period; and (2) cost allocation methods resulting from a State Agreement Process.[1815] The Commission explained that this decision was consistent with application of Order No. 1000 and past precedent, noting that 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).'' [1816] Additionally, the Commission noted that 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.[1817]

c. Requests for Rehearing and Clarification

721. Several commenters argue that Order No. 1920 violates the APA's notice-and-comment requirements because, contrary to the NOPR proposal, it does not require cost allocation methods to comply with Order No. 1000's regional cost allocation principle (6) and prohibits transmission providers from adopting different cost allocation methods for different types of transmission facilities.[1818] NRECA characterizes the change as an ''about face'' from both the NOPR and existing Commission policy.[1819]

722. NRECA additionally argues that Order No. 1920 violates the APA's notice-and-comment requirements because, contrary to the NOPR, Order No. 1920 does not require a transmission provider's 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 required Engagement Period, and does not require a cost allocation method resulting from the State Agreement Process to comply with any of the Order No. 1000 regional cost allocation principles.[1820] NRECA argues that the ''Final Rule's flip-flops on these fundamental requirements for Long-Term Regional Transmission Cost Allocation Methods and the cost allocation methods resulting from a State Agreement Process are not a

[1811] NOPR, 179 FERC ¶ 61,028 at PP 302, 312.

[1812] *Id.* P 312.

[1813] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[1814] Order No. 1920, 187 FERC ¶ 61,068 at P 1469.

[1815] *Id.* P 1470.

[1816] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225, at P 3 (2021)).

[1817] *Id.* (citing *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 (2013); *Consol. Edison Co. of N.Y., Inc.,* 180 FERC ¶ 61,106, at PP 48–50 (2022)).

[1818] Arizona Commission Rehearing Request at 17–19; East Kentucky Rehearing Request at 1–2; NRECA Rehearing Request at 6, 16–17.

[1819] NRECA Rehearing Request at 16–17.

[1820] *Id.* at 6, 17.

logical outgrowth of the NOPR's exactly opposite proposals.'' [1821]

d. Commission Determination

723. We find, and disagree with rehearing requests to the contrary, that the Commission provided adequate notice of and opportunity to comment on the determination in Order No. 1920 to require transmission providers to demonstrate compliance with Order No. 1000 regional cost allocation principles (1) through (5) but not Order No. 1000 regional cost allocation principle (6) for Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed.

724. Courts applying the logical outgrowth doctrine have permitted agencies to drop elements of proposed rules ''even if a resulting final rule effectively abandons an agency's initial proposal'' if the result is ''reasonably foreseeable.'' [1822] Order No. 1920 is a logical outgrowth of the NOPR in this regard, and the APA's notice-and-comment requirements are therefore satisfied.[1823] In the NOPR, the Commission expressed concern that transmission providers are not engaging in long-term, more comprehensive regional transmission planning and cost allocation processes like MISO's MVP process, which identifies projects that are projected to provide *multiple* kinds of reliability and economic benefits.[1824] The Commission proceeded to endorse this kind of transmission planning.[1825] The Commission also noted expressly that ''we preliminarily find that the cost allocation requirements for transmission facilities identified and selected in the regional transmission plan through Long-Term Regional Transmission Planning proposed in this proceeding may differ in part from those established in Order No. 1000.'' [1826]

725. But allowing transmission providers to establish reliability, economic, or public policy transmission facility types, which would have been possible under the NOPR proposal, reflects a more siloed approach to regional transmission planning and cost allocation that commenters argued is misaligned with the reforms in Order No. 1920 and urged the Commission to avoid.[1827] Indeed, the Commission specifically noted its concern that using ''only a subset of benefits in assigning the cost of Long-Term Regional Transmission Facilities may contribute to the risk of free rider problems that impede development of the more efficient or cost-effective regional transmission facilities.'' [1828] That observation, which was made in the context of benefits used as the basis to allocate the costs of Long-Term Regional Transmission Facilities, further indicated the Commission's concerns with the siloed status quo approach and mirrored the rationale that the Commission adopted in eliminating regional cost allocation principle (6). It was therefore reasonably foreseeable that Order No. 1920 would not require compliance with regional cost allocation principle (6), which allows for project-type-limited Long-Term Regional Transmission Cost Allocation Methods, because such an approach would be inconsistent with Order No. 1920's long-term, forward-looking, more comprehensive regional transmission planning.[1829] However, as noted below, transmission providers and Relevant State Entities have broad flexibility to recognize the different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits.

726. Further, courts have held that a final rule satisfies the logical outgrowth standard where an agency either finalizes only part of a multi-segment proposal [1830] or chooses not to finalize a proposal.[1831] Order No. 1920 is a logical outgrowth of the NOPR in this regard. Because the NOPR proposed to require compliance with the existing six Order No. 1000 regional cost allocation principles, the Commission's decision to refrain from requiring compliance with one of those principles—principle (6)—could have been reasonably anticipated by commenters, especially given the Commission's frequently stated concerns regarding the siloing of transmission facilities into different categories under Order No. 1000.[1832] Indeed, in NOPR comments, parties expressed support for modifying Order No. 1000's cost allocation principles.[1833] Such comments are evidence that parties had adequate notice that the Commission might refrain from taking the NOPR's proposed step—*i.e.,* requiring compliance with all six regional cost allocation principles.[1834]

727. For similar reasons, we also disagree that the Commission failed to provide adequate notice of and opportunity to comment on the determination in Order No. 1920 to not adopt the requirement that transmission providers demonstrate compliance with any of the six Order No. 1000 regional cost allocation principles for Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed as part of the Engagement Period or for cost allocation methods resulting from a State Agreement Process. In the NOPR, 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 comply with the six Order No. 1000 regional cost allocation principles.[1835] As noted above, because ''[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step,'' [1836] the

[1821] *Id.* at 16–17.

[1822] *Mid Continent Nail Corp.* v. *U.S.,* 846 F.3d 1364, 1374 (Fed. Cir. 2017) (citing *Long Island Care,* 551 U.S. at 174–75).

[1823] *Id.* at 1373 (''The dispositive question in assessing the adequacy of notice under the APA is whether an agency's final rule is a 'logical outgrowth' of an earlier request for comment.'').

[1824] NOPR, 179 FERC ¶ 61,028 at P 31.

[1825] *Id.* P 33.

[1826] *Id.* P 299. Although the Commission then gave the example of greater state involvement as one way that the cost allocation requirements might differ, that statement was sufficient to put commenters on notice that the Commission would not necessarily adopt in full Order No. 1000's requirements regarding cost allocation. Indeed, as noted below, multiple commenters, including New Jersey Commission and PIOs, expressed support for modifying Order No. 1000's cost allocation principles, indicating their understanding that such potential modifications could be adopted in a final rule.

[1827] *See* Acadia Center and CLF NOPR Initial Comments at 16–17; Massachusetts Attorney General NOPR Initial Comments at 21; PIOs NOPR Initial Comments at 46, 60–62.

[1828] NOPR, 179 FERC ¶ 61,028 at P 325.

[1829] Order No. 1920, 187 FERC ¶ 61,068 at P 1474.

[1830] *Ariz. Pub. Serv. Co.* v. *EPA,* 211 F.3d at 1297–1300 (finding sufficient notice where agency first proposed that Indian tribes be required to meet the ''same requirements'' as states with respect to judicial review of permits issued pursuant to the Clean Air Act, but then adopted a final rule that exempted tribes from some, though not all, such requirements).

[1831] *New York* v. *EPA,* 413 F.3d at 44 (per curiam) (''One logical outgrowth of a proposal is surely . . . to refrain from taking the proposed step.'' (quoting *Am. Iron & Steel Inst.* v. *EPA,* 886 F.2d at 400); *see also Long Island Care,* 551 U.S. at 175 (stating, in the context of rejecting claims that an agency provided legally defective notice because it did not finalize a proposed rule, ''[w]e do not understand why such a possibility was not reasonably foreseeable''); *Vanda Pharms.,* 98 F.4th at 498 (finding that the APA's ''notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content'').

[1832] *See* NOPR, 179 FERC ¶ 61,028 at PP 67, 325.

[1833] New Jersey Commission NOPR Initial Comments at 18 (expressing support for a requirement that any cost allocation method comply with the Order No. 1000 regional cost allocation principles except principle (4)); PIOs NOPR Initial Comments at 61 & n.172 (requesting ''that the Commission specifically find that cost allocation of public policy projects without consideration of economic and reliability benefits is unjust, unreasonable, and unduly discriminatory'').

[1834] *Miami-Dade Cnty.* v. *EPA,* 529 F.3d 1049, 1059 (11th Cir. 2008) (''[A]lthough they may not provide the only basis upon which an agency claims to have satisfied the notice requirement, comments may be adduced as evidence of the adequacy of notice.'').

[1835] NOPR, 179 FERC ¶ 61,028 at P 302.

[1836] *New York* v. *EPA,* 413 F.3d at 44.

Commission's decision to refrain from adopting the entire proposal as to Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have agreed or for cost allocation methods resulting from a State Agreement Process could have been reasonably anticipated by commenters. Moreover, the decision to refrain from adopting the proposal was all the more foreseeable because, as a result of that decision, the cost allocation requirements adopted in Order No. 1920 are more closely aligned with the Commission's existing cost allocation requirements,[1837] which it had already articulated at the time it issued the NOPR, and under which cost allocation methods corresponding to voluntarily negotiated alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s) need not comply with Order No. 1000.[1838]

2. Omission of Regional Cost Allocation Principle No. 6 and Ability To Allocate Costs by Type of Project

a. Order No. 1920 Requirements

728. In Order No. 1920, the Commission declined to 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).[1839] The Commission explained that Order No. 1000 regional cost allocation principle (6) allows for cost allocation methods based on different types of transmission facilities (*i.e.,* reliability, economic, or public policy transmission facility types), but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance.[1840] The Commission found that project-type-limited Long-Term Regional Transmission Cost Allocation Methods that would be permitted by applying regional cost allocation principle (6) are inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning required in Order No. 1920.[1841] 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.[1842]

b. Requests for Rehearing and Clarification

729. Many parties argue that the Commission erred in not requiring the application of Order No. 1000 regional cost allocation principle (6) and request that the Commission implement such a requirement so that transmission providers may allocate the cost of Long-Term Regional Transmission Facilities by project type.[1843] Nearly all of these parties argue that not requiring the application of regional cost allocation principle (6) will result in cost allocation that violates cost causation or the ''beneficiary pays'' principle.[1844] Utah Commission asserts that the Commission not requiring the application of regional cost allocation principle (6) in Order No. 1920 violates cost causation principles by flatly enjoining any cost allocation method that distinguishes between projects that are based on economic or engineering necessity and those based on the ''public policy'' preferences of states, local governments, and corporations.[1845] Several parties argue that Order No. 1920 will result in cost allocation that fails to reflect the role of state policy in causing costs and will shift the financial burden away from the cost-causing states that imposed those policies.[1846] Idaho Commission argues that Order No. 1920 contradicts the Commission's position in Order No. 1000, which stresses the role of states in consideration of costs potentially allocated across multiple states with respect to transmission needs driven by states' individual Public Policy Requirements.[1847]

730. Ohio Commission Federal Advocate argues that the prohibition against transmission providers allocating costs for Long-Term Regional Transmission Facilities based on reliability, economic, and Public Policy Requirement project types is not possible to reconcile with the principle that cost allocation ought to be roughly commensurate with benefits. Ohio Commission Federal Advocate offers as an example a transmission facility that would not exist but for the policy of one or more states, does not affect the power flow in any neighboring states, and does not provide any tangible benefit to any other states, arguing that the Commission ought to clarify that, in this instance, it is wholly appropriate that the sponsoring state or states bear the full cost of the facility and that it would be an unjust and unreasonable result to assign any costs to any other state. Ohio Commission Federal Advocate argues that Ohioans were not afforded the opportunity to weigh in on the policies of other states, nor were they granted a vote on the politicians enacting them, and, as such, should not be assigned any costs associated with those policies.[1848]

731. Some parties assert that the Commission's decision not to require the application of regional cost allocation principle (6) and the prohibition against Long-Term Regional Transmission Facility types and associated cost allocation methods is arbitrary and capricious[1849] because the Commission has not provided a reasonable explanation or any supporting evidence as to how, among other things, this policy will protect consumers from unjust, unreasonable, and unduly discriminatory transmission rates;[1850] the Commission did not explain how the rejection of project-type cost allocation is forward-looking or comprehensive;[1851] and the Commission did not meaningfully distinguish how Long-Term Regional Transmission Planning differs from regional transmission planning under Order No. 1000.[1852] Dominion asserts

[1837] *Cf. New York* v. *EPA,* 413 F.3d at 44 (agency satisfied APA's notice-and-comment requirements where it adopted the approach of the ''status quo ante'' rather than the proposed approach).

[1838] Order No. 1920, 187 FERC ¶ 61,068 at P 1476 (citing *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).

[1839] *Id.* P 1469.

[1840] *Id.* P 1474.

[1841] *Id.*

[1842] *Id.* P 1469.

[1843] Arizona Commission Rehearing Request at 18–19; Dominion Rehearing Request at 28–31; East Kentucky Rehearing Request at 3; Idaho Commission Rehearing Request at 2–4; Indicated PJM TOs Rehearing Request at 2–3, 4–6; Montana Commission Rehearing Request at 1, 4–6; Northern Virginia Rehearing Request at 5, 9–13; NRECA Rehearing Request at 49–55; Ohio Commission Federal Advocate Rehearing Request at 13–15; Utah Commission Rehearing Request at 9–10; West Virginia Commission Rehearing Request at 6–8; Wyoming Commission Rehearing Request at 4–6.

[1844] Arizona Commission Rehearing Request at 18–19; Idaho Commission Rehearing Request at 2–4; Indicated PJM TOs Rehearing Request at 2–3, 4–6; Montana Commission Rehearing Request at 1, 4–6; Northern Virginia Rehearing Request at 5, 9–13; NRECA Rehearing Request at 53–54; Utah Commission Rehearing Request at 9–10; West Virginia Commission Rehearing Request at 6–8; Wyoming Commission Rehearing Request at 4–6.

[1845] Utah Commission Rehearing Request at 9–10.

[1846] Idaho Commission Rehearing Request at 3–4; Montana Commission Rehearing Request 5–6; West Virginia Commission Rehearing Request at 7–8; Wyoming Commission Rehearing Request at 5–6.

[1847] Idaho Commission Rehearing Request at 3 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486).

[1848] Ohio Commission Federal Advocate Rehearing Request at 13–15.

[1849] *E.g.,* Northern Virginia Rehearing Request at 5.

[1850] East Kentucky Rehearing Request at 3.

[1851] Ohio Commission Federal Advocate Rehearing Request at 10.

[1852] Dominion Rehearing Request at 29–30.

that Order No. 1920 does not cite any record evidence, nor is it clear whether any commenters to the NOPR requested this change to Order No. 1000's cost allocation principles.[1853]

732. Dominion argues that Order No. 1920 inappropriately treats all Long-Term Regional Transmission Facilities as equal for cost allocation purposes under the guise of the holistic transmission planning that Order No. 1920 seeks to foster. Dominion further argues that holistic transmission planning can acknowledge that certain projects provide different types of benefits and serve different needs, but together, as a package, serve a variety of needs. Dominion asserts that, if cost allocation cannot be tied to an identified underlying driver for the project, costs are more likely to be inappropriately socialized to customers who did not cause the need and do not benefit from it. Dominion states that the Commission should continue to allow transmission providers to develop different project types and associated cost allocations, but also require that transmission providers have a category of projects to act as a backstop that accounts for all potential benefits.[1854]

733. NRECA argues that the Commission's argument in support of its prohibition on using different cost allocation methods for different types of Long-Term Regional Transmission Facilities is essentially that the Commission can restrict cost allocation methods by dictating planning methods.[1855] NRECA contends that this prohibition and reasoning is contrary to precedent and the Order No. 1000 regional cost allocation principle (1) that Order No. 1920 adopts because it would result in the costs of transmission facilities being allocated in a manner that is not at least roughly commensurate with estimated benefits.[1856] NRECA argues that, if Long-Term Regional Transmission Facilities produce multiple types of benefits that must be accounted for in Long-Term Regional Transmission Planning, this is an argument for a more flexible and more tailored approach to cost allocation with different cost allocation methods, not a more prescriptive and less tailored approach.[1857]

734. NRECA contends that allocating costs of a Long-Term Regional Transmission Facility built to satisfy Public Policy Requirements or other expansive factors required by the rule, such as corporate commitments, in the same manner as a facility built for reliability or economic purposes also likely conflicts with Order No. 1000's regional cost allocation principle (2) because those that receive no benefits would likely be involuntarily allocated costs.[1858] NRECA argues that costs associated with Long-Term Regional Transmission Facilities built to satisfy transmission needs driven by corporate commitments should be borne by the relevant corporations, not by other transmission customers that do not benefit from the facility.[1859]

735. NRECA further argues that the omission of principle (6) and prohibition on using different cost allocation methods for different types of Long-Term Regional Transmission Facilities violates Order No. 1000's regional cost allocation principle (4) because it will likely allow the costs of Long-Term Regional Transmission Facilities built to satisfy a state's Public Policy Requirements to be allocated to customers in other states.[1860]

736. Arizona Commission, Ohio Commission Federal Advocate, and NRECA argue that the Commission's decision not to require the application of regional cost allocation principle (6) and the prohibition against Long-Term Regional Transmission Facility types and associated cost allocation methods replaces flexibility with a one-size-fits-all requirement.[1861] Idaho Commission contends that Order No. 1920 strays from Order No. 1000's "light touch," highlighted in *South Carolina Public Service Authority* v. *FERC,* where the Commission did not "dictate how costs are to be allocated." [1862]

737. Indicated PJM TOs request that the Commission clarify that, by precluding transmission providers from adopting Long-Term Regional Transmission Cost Allocation Methods for different project types, it did not intend to preclude transmission providers from adopting cost allocation methods that allocate costs based on the different benefits associated with a particular facility. Indicated PJM TOs argue that such a clarification would be consistent with the Commission's obligation to ensure that the transmission provider allocates the cost in a manner that is at least roughly commensurate with estimated benefits. Indicated PJM TOs state that, if the Commission does not grant this clarification, they seek rehearing of the decision to preclude transmission providers from adopting different Long-Term Regional Transmission Cost Allocation Methods based on a facility's benefits because this outcome is inconsistent with other statements in the NOPR and Order No. 1920 and long-standing cost causation principles and nothing in regional cost allocation principle (6) prevents transmission providers from having this flexibility.[1863]

738. Virginia and North Carolina Commissions argue that the Commission should afford transmission providers, in coordination with Relevant State Entities and other stakeholders, the maximum flexibility possible with respect to potential *ex ante* cost allocation methods, so long as such methods are in compliance with the Commission's cost-causation principles. As a result, Virginia and North Carolina Commissions assert that the Commission should clarify on rehearing that Order No. 1920 does not expressly preclude cost allocation methods that allocate costs based on the incremental costs associated with the inclusion of one or more public policy factors.[1864]

c. Commission Determination

739. We sustain Order No. 1920's decision to not require Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities do not agree to comply with Order No. 1000 regional cost allocation principle (6), and also sustain the prohibition of cost allocation methods that allocate costs based solely on one type of benefit, such as reliability, economic, and public policy transmission facility types. However, we note our clarification below that transmission providers and Relevant State Entities may consider different types of benefits provided by Long-Term Regional Transmission Facilities and allocate costs in proportion to those benefits.[1865] Recognizing the flexibility

[1853] *Id.* at 29.

[1854] *Id.* at 29–31.

[1855] NRECA Rehearing Request at 53.

[1856] *Id.* (citing *ICC* v. *FERC I,* 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at P 622).

[1857] *Id.* at 54.

[1858] *Id.*

[1859] *Id.* at 55.

[1860] *Id.* Order No. 1000 regional cost allocation principle (4) provides that costs must be allocated "solely within th[e] transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs." Order No. 1000, 136 FERC ¶ 61,051 at P 657.

[1861] Arizona Commission Rehearing Request at 18–19; Ohio Commission Federal Advocate Rehearing Request at 14; NRECA Rehearing Request at 52, 54.

[1862] Idaho Commission Rehearing Request at 3 (quoting *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 81).

[1863] Indicated PJM TOs Rehearing Request at 2–3, 4–6.

[1864] Virginia and North Carolina Commissions Rehearing Request at 5–6.

[1865] *See infra* Concerns Regarding Cost Causation section.

to allocate costs in proportion to different types of benefits, we disagree with arguments raised on rehearing that the Commission should require the application of Order No. 1000 regional cost allocation principle (6) to Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed and arguments that the Commission's decision on this issue is arbitrary and capricious. First, because of the flexibility the Commission provided to transmission providers to propose different cost allocation methods for Long-Term Regional Transmission Facilities, we disagree that a requirement not to use cost allocation methods that allocate costs based on project types will result in adoption of cost allocation methods that violate the cost causation principle. We reiterate that, as stated in Order No. 1920, the Commission will evaluate each proposed Long-Term Regional Transmission Cost Allocation Method to ensure that it will allocate costs in a manner that is at least roughly commensurate with the estimated benefits that Long-Term Regional Transmission Facilities will provide, which will ensure compliance with the cost causation principle and the just and reasonable standard more broadly.[1866] To the extent that a party believes that any Long-Term Regional Transmission Cost Allocation Method submitted on compliance, including those discussed herein, violates the cost causation principle, it will have the opportunity to raise those concerns in response to the compliance filing.

740. Additionally, as the Commission found in Order No. 1920, Long-Term Regional Transmission Facilities are likely to provide a diverse array of benefits,[1867] and Order No. 1920 specifically required that transmission providers consider seven economic and reliability benefits,[1868] while not prohibiting them from also considering public policy benefits.[1869] We conclude that Long-Term Regional Transmission Facilities will likely have benefits beyond addressing transmission needs driven by Public Policy Requirements and allowing transmission providers to allocate costs based solely on one type of benefit, such as reliability, economic, or public policy transmission project types, would likely underestimate the benefits provided by the project and, for that reason, be inconsistent with the goals underlying long-term, forward-looking, more comprehensive regional transmission planning required in Order No. 1920.[1870]

741. Nevertheless, we emphasize the fundamental principle that costs must be allocated in a manner that is at least roughly commensurate with estimated benefits, ensuring that ratepayers will not pay for facilities from which they do not benefit.[1871] Regardless of the factors driving the need for that project, if a customer does not derive benefits from the project or if they derive only trivial benefits in relation to the project's costs, the customer cannot be forced to pay for the costs of the project without violating the cost causation principle.[1872]

742. Additionally, contrary to Dominion's argument,[1873] the long-term, forward-looking, more comprehensive nature of Long-Term Regional Transmission Planning distinguishes it from regional transmission planning under Order No. 1000. Order No. 1000 did not establish similarly long-term, forward-looking, or comprehensive regional transmission planning requirements. As a result, the Commission engaged in reasoned decision-making in relying on the different attributes of Long-Term Regional Transmission Planning when not adopting Order No. 1000 regional cost allocation principle (6).

743. As the Commission also found in Order No. 1920, the application of Order No. 1000 regional cost allocation principles (1) through (5) safeguards against cost causation concerns. Notably, the Commission explained:

> [P]rinciples (1) and (2) require that benefits received are at least roughly commensurate with costs paid and that costs may not be involuntarily allocated to those that do not benefit, respectively. Further, Order No. 1000 regional cost allocation principle (5), as well as the requirements in this final rule 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.[1874]

744. Therefore, even if a Long-Term Regional Transmission Facility helps to address a transmission need driven by a state or states' Public Policy Requirements, the costs of that transmission facility will only be allocated to ratepayers in states without those Public Policy Requirements in relation to the benefits they receive. We note that the benefits of a transmission facility go beyond any particular need that it may address.[1875] As noted below, where Relevant State Entities agree, one potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation.[1876]

745. For these reasons, we disagree with rehearing arguments that seem to suggest that, for any Long-Term Regional Transmission Cost Allocation Method to satisfy the cost causation principle or, in NRECA's case, not contradict Order No. 1000 principles (1) and (2),[1877] transmission providers must disaggregate all disparate drivers of Long-Term Transmission Needs so that each identified Long-Term Regional Transmission Facility may precisely be attributed to a particular policy goal or other driver of the transmission need. As we emphasize throughout this section, transmission providers and Relevant State Entities have broad flexibility to develop cost allocation approaches, provided such approaches comply with the cost causation principle and are otherwise just and reasonable. Consistent with that flexibility, as we clarify below, transmission providers and Relevant State Entities are not precluded from considering in their proposed cost

[1866] Order No. 1920, 187 FERC ¶ 61,068 at PP 1305 & n.2786, 1478; *see 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.'' (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 [*i.e.,* the just and reasonable standard], establishing what has become known in Commission parlance as the 'cost-causation' principle.'').

[1867] Order No. 1920, 187 FERC ¶ 61,068 at PP 123, 126, 722.

[1868] *See id.* PP 719–720.

[1869] *Id.* PP 737, 822; *see also id.* P 1515 & n.3220.

[1870] *Id.* P 1474.

[1871] *Id.* P 267.

[1872] *ICC* v. *FERC I,* 576 F.3d at 476–77; *ICC* v. *FERC III,* 756 F.3d at 564–65; *see Coal. of MISO Transmission Customers* v. *FERC,* 45 F.4th 1004, 1009 (D.C. Cir. 2022); *LSP Transmission Holdings II, LLC* v. *FERC,* 45 F.4th 979, 984 (D.C. Cir. 2022).

[1873] Dominion Rehearing Request at 30.

[1874] Order No. 1920, 187 FERC ¶ 61,068 at P 1478.

[1875] *See ICC* v. *FERC I,* 576 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.''). *See also* Order No. 1000, 136 FERC ¶ 61,051 at P 690 (''If a regional transmission plan determines that a regional transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.'').

[1876] *See infra* Concerns Regarding Cost Causation section.

[1877] NRECA Rehearing Request at 53–55.

allocation methods the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. Nevertheless, we find that requiring transmission providers to conduct Long-Term Regional Transmission Planning in the manner suggested by NRECA might risk undermining the scaling of Long-Term Regional Transmission Facilities to provide a more efficient or cost-effective solution to multiple transmission needs by encouraging piecemeal transmission expansion (*e.g.,* two separate transmission facilities to address two separate transmission needs may be more expensive than one facility meeting both needs) that caused the need for reform in the first place.[1878] In addition, that exercise would likely stymie transmission providers' selection of more efficient or cost-effective transmission solutions by leading them to ignore or otherwise discount the diverse range of benefits that Long-Term Regional Transmission Facilities can provide, likely leading them to underestimate the benefits that the facilities provide to customers.

746. Moreover, we reiterate that Long-Term Regional Transmission Cost Allocation Methods to which Relevant State Entities have not agreed must satisfy Order No. 1000 regional cost allocation principles (1) through (5), such that transmission customers will only pay for Long-Term Regional Transmission Facilities (or portfolios of such Facilities) when the transmission provider has determined that they meet the transmission providers' selection criteria and transmission customers will only be allocated costs that are at least roughly commensurate with the estimated benefits they receive. As Order No. 1920 noted:

> [U]nder this final rule, 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.[1879]

747. Consequently, and contrary to certain parties' arguments,[1880] these requirements will protect customers from unjust, unreasonable, and unduly discriminatory or preferential transmission rates.

748. Regarding NRECA's arguments that the cost allocation requirements of Order No. 1920 violate Order No. 1000 regional cost allocation principle (4),[1881] we disagree. NRECA's arguments are based on an incorrect interpretation of Order No. 1000 regional cost allocation principle (4), which states that ''[t]he allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that *transmission planning region* unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.'' [1882] Order No. 1000 regional cost allocation principle (4) concerns transmission planning regions, not individual states as contemplated by NRECA's arguments, and it does not prohibit allocation of costs among customers in states within a single transmission planning region.

749. We disagree with rehearing parties who argue that the lack of a requirement to apply regional cost allocation principle (6), with its prohibition against adopting different Long-Term Regional Transmission Cost Allocation Methods for reliability, economic, and public policy transmission project types, creates a one-size-fits-all approach,[1883] inappropriately treats all Long-Term Regional Transmission Facilities as equal for cost allocation purposes,[1884] or otherwise conflicts with the Commission's ''light touch'' in Order No. 1000.[1885] In particular, NRECA is incorrect that the prohibition against adopting different Long-Term Regional Transmission Cost Allocation Methods for reliability, economic, and public policy transmission project types means that ''transmission providers must similarly use a single cost allocation method.'' [1886] Rehearing parties' arguments focus on the prohibition against economic, reliability, and public policy types, but do not recognize the broad flexibility otherwise afforded under Order No. 1920's application of Order No. 1000 regional cost allocation principles (1)–(5) and allowance of multiple cost allocation methods for Long-Term Regional Transmission Facilities.[1887] Under Order No. 1920, transmission providers may craft different *ex ante* cost allocation methods to reflect the different proportion of benefits provided by Long-Term Regional Facilities with different underlying drivers.[1888] Thus, we clarify that Order No. 1920's prohibition against types is a prohibition against the allocation of costs based on a single category of benefits—whether reliability, economic, public policy, or another category of benefits. In other words, transmission providers could *not* allocate *all* costs of Long-Term Regional Transmission Facilities on the basis of public policy benefits, if doing so ignores economic and reliability benefits associated with those facilities. Allocating the costs of Long-Term Regional Transmission Facilities entirely on a single category of benefits would likely ignore the diverse range of benefits those Facilities likely provide, as described above, and in doing so violate the cost causation principle.

750. We reiterate the fact that Order No. 1920 provides flexibility previously unafforded in regional transmission planning both in the new types of compliant cost allocation methods (*i.e.,* Long-Term Regional Transmission Cost Allocation Methods agreed to by Relevant State Entities during the Engagement Period and cost allocation methods resulting from a State Agreement Process) and in the lack of restrictions placed on these new state-agreed-to methods (*i.e.,* the only requirement for such methods is compliance with the cost causation principle). We believe the possibilities afforded by state agreement under Order No. 1920 may address the concerns underlying rehearing parties' arguments.

751. Further, we grant Indicated PJM TOs' request for clarification that Order No. 1920 does not preclude transmission providers from adopting Long-Term Regional Transmission Cost Allocation Methods that allocate costs based on the different benefits associated with a particular Long-Term Regional Transmission Facility (or portfolio of Facilities).[1889] Transmission

[1878] Order No. 1920, 187 FERC ¶ 61,068 at PP 85, 112.

[1879] *Id.* P 270.

[1880] *See e.g.,* East Kentucky Rehearing Request at 3.

[1881] NRECA Rehearing Request at 55.

[1882] Order No. 1000, 136 FERC ¶ 61,051 at P 657 (emphasis added).

[1883] *See* Arizona Commission Rehearing Request at 18–19; Ohio Commission Federal Advocate Rehearing Request at 14.

[1884] *See* Dominion Rehearing Request at 29–31.

[1885] *See* Idaho Commission Rehearing Request at 3; NRECA Rehearing Request at 52–53.

[1886] NRECA Rehearing Request at 53.

[1887] Order No. 1920, 187 FERC ¶ 61,068 at P 1475 (''We clarify that this final rule 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.'').

[1888] *Infra* Concerns Regarding Cost Causation section.

[1889] Indicated PJM TOs Rehearing Request at 2–3, 4–6.

providers may propose *ex ante* Long-Term Regional Transmission Cost Allocation Methods that, for example, assign a portion of the costs of a Long-Term Regional Transmission Facility that are associated with reliability benefits to one set of beneficiaries, a portion of the costs associated with economic benefits to another set of beneficiaries, and a portion of costs associated with public policy benefits to a different set of beneficiaries. Such a method would not violate the Commission's decision to not apply regional cost allocation principle (6) because the Long-Term Regional Transmission Cost Allocation Method would not create a cost allocation method that is specific to, for example, a transmission facility that satisfies a transmission need driven by economic benefits. As such, elimination of Order No. 1000 regional cost allocation principle (6) does not yield as inflexible an outcome as rehearing partis assert.

752. In response to Virginia and North Carolina Commissions' request that the Commission clarify that Order No. 1920 does not preclude cost allocation methods that allocate costs based on the incremental costs associated with the inclusion of one or more public policy factors,[1890] we clarify that Order No. 1920's cost allocation requirements allow for, but do not require, transmission providers to account for the benefits associated with addressing transmission needs driven by Public Policy Requirements in any *ex ante* cost allocation method.[1891]

3. Concerns Regarding Cost Causation

a. Order No 1920 Requirements

753. In Order No. 1920, the Commission required Long-Term Regional Transmission Cost Allocation Methods not agreed to by Relevant State Entities to comply with Order No. 1000 regional cost allocation principles (1) through (5). The Commission found 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 for which Relevant State Entities have *not* indicated their agreement.[1892]

754. In Order No. 1920, the Commission did not require transmission providers to demonstrate that Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to or cost allocation methods resulting from a State Agreement Process comply with any of the Order No. 1000 regional cost allocation principles.[1893] The Commission chose not to adopt the NOPR proposal to require adherence to the six Order No. 1000 regional cost allocation principles in these circumstances 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.[1894] The Commission further reasoned that affording additional flexibility for these methods by not requiring the application of the six Order No. 1000 regional cost allocation principles may encourage their use, and consequently facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[1895] The Commission noted, however, that such methods must still 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.[1896] The Commission further explained that this decision was consistent with past precedent, noting that 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)."[1897] Additionally, the Commission noted that 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.[1898] Consistent with this precedent, the Commission found that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to and have asked transmission providers to file also qualify as voluntary alternative cost sharing arrangements and, accordingly, the Commission declined to require those methods to adhere to the six Order No. 1000 regional cost allocation principles.[1899] However, the Commission did require that any voluntary alternative cost sharing arrangements still comply with the cost causation principle and any other legal requirements for cost allocation.[1900]

b. Requests for Rehearing and Clarification

755. NRECA argues that Order No. 1920 does not provide a reasonable explanation for its decision not to require a Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles when Relevant State Entities indicate their agreement with such a method as part of the Engagement Period.[1901] NRECA further argues that Order No. 1920 similarly does not provide a reasonable explanation as to why the Commission did not require a cost allocation method resulting from a State Agreement Process to comply with the Order No. 1000 regional cost allocation principles.[1902] NRECA contends that neither Order No. 1920's reliance on a 2021 Commission policy statement nor Order No. 1000 allows the Commission to waive the Order No. 1000 regional cost allocation principles as NRECA alleges the Commission does in the final rule.[1903] NRECA asserts that Order No. 1920's reference to prior instances where the Commission has approved voluntary agreements on a case-by-case basis without finding that their cost allocation methods comply with Order No. 1000 does not constitute precedent for a categorical waiver of Order No. 1000's requirements for future cost

[1890] Virginia and North Carolina Commissions Rehearing Request at 5–6.

[1891] *See infra* Concerns Regarding Cost Causation section.

[1892] Order No. 1920, 187 FERC ¶ 61,068 at PP 1469, 1472–1473.

[1893] *Id.* PP 1470, 1476.

[1894] *Id.* P 1477.

[1895] *Id.*

[1896] *Id.* (citation omitted).

[1897] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at P 3).

[1898] *Id.* (citing *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).

[1899] *Id.*

[1900] *Id.*

[1901] NRECA Rehearing Request at 55.

[1902] *Id.* at 55–56.

[1903] *Id.* at 56 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1476; *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225).

allocations methods reached under the State Agreement Process.[1904]

756. NRECA argues that Order No. 1920 adopts cost allocation requirements that are more prescriptive in some respects (*e.g.,* prohibiting transmission providers from using different cost allocation methods for different project types) but less prescriptive in other respects (*e.g.,* not requiring compliance with any Order No. 1000 regional cost allocation principles when states agree on a cost allocation method). NRECA contends that this results in opaque, lax, and inconsistent standards for cost allocation for Long-Term Regional Transmission Facilities. NRECA asserts that, as a result, the Commission will be unable to enforce the FPA's requirements against unjust, unreasonable, or unduly discriminatory or preferential rates.[1905]

757. Arizona Commission argues that Order No. 1920 usurps Arizona's constitutional requirements that the Arizona Commission must apply rates that are fair and reasonable and that it must not recover costs from ratepayers that do not cause, or benefit from, a particular cost.[1906] Arizona Commission further argues that the cost allocation methods adopted in the final rule are contrary to existing ratemaking principles, which include providing customers with reliable power at the least cost and allocating costs to the entities that cause them.[1907] Ohio Consumers similarly claim that Order No. 1920 is arbitrary and capricious and violates policy and precedent that requires that costs be allocated consistent with those who receive benefits.[1908]

758. Virginia and North Carolina Commissions assert that the Commission must ensure public policies considered in planning criteria and scenarios are also appropriately accounted for in any *ex ante* cost allocation method to avoid cross-subsidization of state public policy goals. Virginia and North Carolina Commissions state that the Commission should clarify on rehearing that to comport with the Commission's cost-causation principles, any proposed *ex ante* cost allocation method must adequately account for not only the benefits resulting from an identified transmission project, but also the cost drivers (or cost causers) that contribute to the need for the transmission project. Alternatively, Virginia and North Carolina Commissions argue that the Commission should expressly require the same public policy factors included in the Long-Term Scenarios to be considered as potential benefits for cost allocation purposes.[1909]

759. West Virginia Commission and Wyoming Commission argue that Order No. 1920's transmission planning and cost allocation requirements force transmission providers within their states to plan projects based on decarbonization goals of other states in the region.[1910] West Virginia Commission and Wyoming Commission further argue that this would require transmission providers in the state to account for abstract assumed benefits for its retail customers.[1911] West Virginia Commission and Wyoming Commission contend that, in the event that the costs allocated to retail customers exceed benefits that their respective state policies realize from regional transmission projects, they will be forced to assign unjust and unreasonable costs to retail customers or deny a utility a potentially significant portion of its expected cost recovery.[1912] Wyoming Commission argues that this result is contrary to core principles of utility regulation and wrongfully empowers states to exact the costs of their policy initiatives from ratepayers in other states.[1913]

c. Commission Determination

760. We disagree with NRECA's arguments that the Commission did not provide a reasonable explanation for its decision not to require cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file to comply with any of the Order No. 1000 regional cost allocation principles.[1914] We continue to 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 are likely to facilitate agreement concerning 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 costs 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.[1915] Further, we continue to find that 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.[1916] In short, we find that the benefits of providing additional flexibility for state-agreed-upon cost allocation methods for Long-Term Regional Transmission Facilities outweigh NRECA's concerns regarding not applying the Order No. 1000 regional cost allocation principles, such that it represents a just and reasonable approach to these issues.

761. Additionally, we highlight that the cost causation principle and Commission precedent require the Commission to evaluate each proposed cost allocation method to determine whether it will allocate costs in a manner that is at least roughly commensurate with estimated benefits and whether the proposed method is just and reasonable and not unduly discriminatory or preferential, as stated in Order No. 1920.[1917] This is the case whether or not we specifically require these cost allocation methods to comply with the Order No. 1000 regional cost allocation principles.

762. For cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file, we continue to find that such methods qualify as voluntary alternative cost sharing arrangements, consistent with the Commission's previous findings 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)'' [1918] and that the

[1904] *Id.* at 56–57 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1476 n.3150).

[1905] *Id.* at 52.

[1906] Arizona Commission Rehearing Request at 20–21.

[1907] *Id.* at 20.

[1908] Ohio Consumers Rehearing Request at 9.

[1909] Virginia and North Carolina Commissions Rehearing Request at 3–4.

[1910] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1911] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1912] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7–8.

[1913] Wyoming Commission Rehearing Request at 8.

[1914] NRECA Rehearing Request at 55–56.

[1915] Order No. 1920, 187 FERC ¶ 61,068 at P 1477.

[1916] *Id.* (citation omitted).

[1917] *See, e.g., id.* P 1506 (citing *ICC* v. *FERC I,* 576 F.3d at 477; *ICC* v. *FERC III,* 756 F.3d at 564).

[1918] *Id.* P 1476 (quoting *State Voluntary Agreements to Plan & Pay for Transmission Facilities,* 175 FERC ¶ 61,225 at P 3).

Commission need not find that cost allocation methods corresponding to such voluntary agreements comply with Order No. 1000.[1919] Therefore, in response to NRECA, we continue to decline to require such cost allocation methods to adhere to the six Order No. 1000 regional cost allocation principles.[1920]

763. We further disagree with NRECA's arguments that the cost allocation requirements adopted in Order No. 1920 will result in inconsistent standards for cost allocation for Long-Term Regional Transmission Facilities and will result in the Commission's inability to enforce the FPA's requirements against unjust, unreasonable, and unduly discriminatory or preferential rates.[1921] We recognize that there are different requirements for cost allocation methods resulting from a State Agreement Process or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file as compared to Long-Term Regional Transmission Cost Allocation Methods to which states do not agree, but we find that the potential for differences is appropriate to give states flexibility.[1922] Regardless, we reiterate that all cost allocation methods must comply with the cost causation principle, as required by the FPA.[1923] Additionally, we note that nothing in FPA section 206 requires that transmission providers adopt the same or similar proposals on compliance provided that they comply with Order No. 1920.

764. We also disagree with arguments raised by Arizona Commission and Ohio Consumers on rehearing that Order No. 1920's transmission planning and cost allocation requirements are inconsistent with cost causation principles.[1924] All cost allocation methods for Long-Term Regional Transmission Facilities, including Long-Term Regional Transmission Cost Allocation Methods, regardless of whether they are agreed to by Relevant State Entities, and cost allocation methods resulting from Commission-approved State Agreement Processes, must comply with the cost causation principle and ensure that the costs of transmission facilities are allocated in a manner at least roughly commensurate with estimated benefits.[1925]

765. In light of our clarification noted below, we find it unnecessary, as requested by Virginia and North Carolina Commissions,[1926] to require transmission providers to demonstrate on compliance how both the benefits resulting from an identified transmission project and the cost drivers contributing to the need for that project are appropriately accounted for in their proposed Long-Term Regional Transmission Cost Allocation Method, or alternatively to require that the same public policy factors included in Long-Term Scenarios be considered as potential benefits for the purposes of cost allocation. Specifically, we note that our clarification regarding the recognition of benefits below in response to West Virginia Commission and Wyoming Commission's request may address Virginia and North Carolina Commissions' concerns regarding the consideration of public policy factors in cost allocation methods. Further, we find that requiring transmission providers to show that the relevant cost allocation methods comply with cost causation by ensuring that costs are allocated in a manner roughly commensurate with benefits will provide flexibility and account for regional diversity while also ensuring that those cost allocation methods comply with the requirements of the FPA.[1927]

766. We disagree with arguments raised on rehearing by West Virginia Commission and Wyoming Commission that Order No. 1920's transmission planning and cost allocation requirements force transmission providers within their states to plan transmission projects based on decarbonization goals of other states in the transmission planning region and require transmission providers to account for abstract assumed benefits.[1928] First, as discussed above, because of the flexibility provided by the Commission regarding cost allocation, it is premature and speculative to assert that a requirement not to use cost allocation methods based on project type will result in adoption of cost allocation methods that violate cost causation principles. We also reiterate that, in the context of transmission facilities, the cost causation principle requires the Commission to ensure that any cost allocation method allocates costs in a manner roughly commensurate with estimated benefits, meaning that if consumers do not benefit from a project they will not be required to pay for it nor will they be required to bear a share of project costs that does not reflect their share of the project's benefits.[1929]

767. Further, we clarify that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion to those benefits. As an example, one potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation. Under this potential cost allocation method, these costs and benefits could be identified based on one or more additional analyses, such as additional scenarios, run by the transmission providers for the purposes of informing cost allocation, *e.g.,* scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. For example, the cost allocation method agreed to by the Relevant State Entities may allocate those incremental costs to states with those applicable laws, policies, and regulations.

768. Noting this clarification, and where Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities agree to are concerned, at the request of the Relevant State Entities in a multistate region, the

[1919] *Id.* (citing *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).

[1920] *Id.*

[1921] NRECA Rehearing Request at 52.

[1922] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1477.

[1923] *Id.* P 1305 & n.2786.

[1924] Arizona Commission Rehearing Request at 20; Ohio Consumers Rehearing Request at 9.

[1925] Order No. 1920, 187 FERC ¶ 61,068 at PP 1305 & n.2786, 1506 (citing *ICC* v. *FERC I,* 576 F.3d at 477; *ICC* v. *FERC III,* 756 F.3d at 564).

[1926] Virginia and North Carolina Commissions Rehearing Request at 3–4.

[1927] *See* Order No. 1920, 187 FERC ¶ 61,068 at 1510.

[1928] West Virginia Commission Rehearing Request at 10; Wyoming Commission Rehearing Request at 7.

[1929] *See* Order No. 1920, 187 FERC ¶ 61,068 at 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.'') (citation omitted)); *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.''); *see also* Order No. 1000, 136 FERC ¶ 61,051 at P 690 (''If a regional transmission plan determines that a transmission facility serves several functions, as many commenters point out it may, the regional cost allocation method must take the benefits of these functions of the transmission facility into account in allocating costs roughly commensurate with benefits.'').

following *ex ante* method for cost allocation may be proposed. In providing this example, we are not foreclosing other approaches for allocating the costs of Long-Term Regional Transmission Facilities on either an *ex ante* basis or through a State Agreement Process. Nor are we suggesting that cost allocation methods must adopt a similar approach to this framework in order to comply with the requirements of Order No. 1920. This example is as follows:

(1) For the purposes of cost allocation, transmission providers shall run an additional scenario analysis to identify transmission needs using the same Long-Term Scenarios and sensitivities used in its Long-Term Regional Transmission Planning process, except that the inputs to such additional scenarios shall not include state laws, policies and regulations. Transmission providers shall identify transmission facilities to meet the needs identified in such additional scenario analysis and those facilities' costs. Transmission providers shall then determine the difference in costs between the set of Long-Term Regional Transmission Facilities selected in the regional transmission plan for purposes of cost allocation and the set of transmission facilities that would be selected based upon the additional scenario analysis.

(2) The portion of total selected Long-Term Regional Transmission Facility costs identified in (1) could be cost allocated according to an existing Commission-accepted cost allocation method that may be proposed on compliance with Order No. 1920.

(3) The amount representing the cost difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) shall be allocated as follows:

a. The transmission providers shall identify by state the specific state laws, policies, and regulations that were used to plan and select the Long-Term Regional Transmission Facilities and shall quantify *by state* the specific costs of such Facilities.

b. The costs identified in 3(a) shall be allocated solely to the state or states that are the sources of the policies used in planning and selection. The total difference between the costs of Long-Term Regional Transmission Facilities selected pursuant to the Long-Term Regional Transmission Planning process and (1) would be fully accounted for using this method of allocating costs among the states. For RTOs/ISOs, the cost allocation to transmission customers in a transmission pricing zone *within* a state would be developed by the applicable Transmission Owner(s). For non-RTOs/ISOs, the costs allocated to transmission customers in a transmission provider's retail distribution service territory or footprint within a state would be developed by the applicable transmission provider.

G. General Benefits Requirements Related to Cost Allocation

1. Logical Outgrowth

a. NOPR Proposals

769. In the NOPR, the Commission proposed for consideration a list of Long-Term Regional Transmission Benefits for transmission providers to apply in Long-Term Regional Transmission Planning and cost allocation processes.[1930] Additionally, the Commission proposed to require that transmission providers identify on compliance the benefits they will use in any *ex ante* cost allocation method, 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.[1931] The NOPR also proposed to require transmission providers to explain the rationale for using the benefits identified.[1932] Additionally, the Commission requested comment on the proposed requirements, whether the Commission should require that transmission providers account for the full list of benefits contained in the NOPR's Evaluation of the Benefits of Regional Transmission Facilities section, or whether no change to the benefits used in existing regional transmission processes was needed.[1933]

b. Order No. 1920 Requirements

770. In Order No. 1920, the Commission declined to adopt the NOPR proposal regarding the use of benefits in Long-Term Regional Transmission Cost Allocation Methods.[1934] Instead, as discussed above in the Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities section, the Commission required transmission providers in each transmission planning region to demonstrate that any Long-Term Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to complies with Order No. 1000 regional cost allocation principles (1) through (5). The Commission did not require transmission providers to demonstrate that Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate they have agreed to or cost allocation methods resulting from a State Agreement Process comply with any of the Order No. 1000 regional cost allocation principles, but the Commission noted that such methods must still 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.[1935] The Commission did 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.[1936]

771. The Commission explained that the modified approach to the relationship of benefits used in Long-Term Regional Transmission Planning and Long-Term Regional Transmission Cost Allocation Methods provides transmission providers with flexibility to propose a Long-Term Regional Transmission Cost Allocation Method(s), allowing for negotiation in the Engagement Period, which the Commission believed will increase the likelihood that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective regional transmission solution will be developed. The Commission additionally explained that the requirements in Order No. 1920 to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities will provide transparency and help to ensure cost allocation is just and reasonable.[1937] Additionally, the Commission reasoned that this flexible approach is consistent with the approach 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.[1938]

c. Requests for Rehearing and Clarification

772. NRECA contends that Order No. 1920's determination not to require transmission providers to disclose which benefits, if any, they use in their regional cost allocation proposals is not a logical outgrowth of the NOPR.[1939] NRECA argues that the requirement to use a stated set of benefits in evaluating

[1930] NOPR, 179 FERC ¶ 61,028 at PP 185, 326.

[1931] *Id.* P 326.

[1932] *Id.*

[1933] *Id.* P 327.

[1934] Order No. 1920, 187 FERC ¶ 61,068 at P 1505.

[1935] *Id.* PP 1470, 1476–1477.

[1936] *Id.* P 1506.

[1937] *Id.*

[1938] *Id.* P 1507 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 560, 624).

[1939] NRECA Rehearing Request at 12–13.

and selecting Long-Term Regional Transmission Facilities, without requiring transmission providers to disclose which benefits were used in their regional cost allocation proposals, allows cost allocation to be ''completely opaque and divorced from the measured benefits.'' [1940]

d. Commission Determination

773. In response to NRECA's argument that the Commission violated the APA's notice-and-comment requirements by declining to adopt the NOPR proposal to require transmission providers to disclose the benefits used in Long-Term Regional Transmission Cost Allocation Methods, we note that certain clarifications adopted herein may alleviate the concerns underlying NRECA's argument. Specifically, as discussed in the Minimum Requirements section above, we clarify in this order that, once transmission providers make a selection decision, *i.e.,* for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities) and the applicable cost allocation method is determined, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how those estimated costs will be allocated, by zone (*i.e.,* by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of the estimated benefits as imputed to each zone, as such benefits can be reasonably estimated, when a cost allocation method is agreed upon under a State Agreement Process or, if no State Agreement Process is used, at the time of project selection.

774. Noting this clarification, we nevertheless disagree with NRECA that the Commission violated the APA's notice-and-comment requirements. Agency final rules need not be identical to proposed rules, and notice is sufficient if the final rule represents a ''logical outgrowth'' of the proposed rule.[1941] Here, the NOPR proposed to require transmission providers to disclose the benefits used in Long-Term Regional Transmission Cost Allocation Methods after noting the Commission's concern that, among other things, the Commission's existing regional transmission planning and cost allocation requirements may result in transmission providers undervaluing the benefits of Long-Term Regional Transmission Facilities for purposes of allocating the costs of such facilities to beneficiaries in a manner that is roughly commensurate with estimated benefits.[1942] While Order No. 1920 did not adopt the NOPR proposal, it included safeguards that will ensure an adequate accounting for benefits in cost allocation methods for Long-Term Regional Transmission Facilities, in addition to the new safeguard we adopt in this order, noted above. For instance, Order No. 1920 noted that any cost allocation method for Long-Term Regional Transmission Facilities will be required to comply with cost allocation precedent, including that costs be allocated in a manner at least roughly commensurate with estimated benefits.[1943] That standard requires that transmission providers show, on compliance, that their proposed cost allocation methods match the allocation of costs associated with the project in a manner that is at least roughly commensurate with the estimated benefits of the project. We find that this approach is sufficiently similar, in practice, to the proposal in the NOPR that it can be said to ''follow logically from'' the NOPR, that the NOPR ''adequately frame[d] the subjects for discussion,'' [1944] and that ''a reasonable member of the regulated class'' could ''anticipate the general aspects of the [final] rule.'' [1945]

2. Substantive Issues

a. Order No. 1920 Requirements

775. In Order No. 1920, the Commission required 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).[1946]

b. Requests for Rehearing and Clarification

776. Clean Energy Associations assert that the Commission should clarify the rights, obligations, and limits associated with transmission providers' adoption of multiple Long-Term Regional Transmission Cost Allocation Methods for comparable transmission facilities within its overall footprint. Further, Clean Energy Associations argue that the Commission should clarify that transmission providers must allocate the costs of similarly situated transmission facilities similarly to avoid undue discrimination and unjust and unreasonable rates.[1947] Clean Energy Associations assert that, although presently unclear, it seems plausible that under Order No. 1920, transmission providers could attempt to allocate the costs of two comparable transmission facilities (similar in costs and benefits) using entirely different methods if the transmission provider considers them to be different ''types'' of projects, based on any categorization rubric other than Order No. 1000's regional cost allocation principle (6).[1948] Clean Energy Associations also request clarification that Order No. 1920 does not preclude transmission providers from adopting a cost allocation approach that seeks to maximize net benefits.[1949]

777. Dominion seeks clarification on the consideration of the seven required benefits in cost allocation such that if a transmission provider opts to rely on all or some of the seven benefits in its cost allocation method, then it may apply different weighting to different benefits, *e.g.,* based on probability of occurrence and certainty of benefit in later years.[1950]

c. Commission Determination

778. We deny Clean Energy Association's request to clarify the rights, obligations, and limits associated with transmission providers' potential adoption of multiple Long-Term Regional Transmission Cost Allocation Methods for comparable transmission facilities within its overall footprint. Order No. 1920 provided guidance regarding transmission providers' use of multiple Long-Term Regional Transmission Cost Allocation Methods, including that transmission providers may adopt multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional

[1940] *Id.*

[1941] *Long Island Care,* 551 U.S. at 174–75. *See also Am. Paper Inst.* v. *EPA,* 660 F.2d at 959 n.13 (''An agency may make *even substantial changes* in its original proposed rule without a further comment period if the changes are in character with the original proposal and are a logical outgrowth of the notice and comments already given.'' (emphasis added)).

[1942] NOPR, 179 FERC ¶ 61,028 at PP 325–326.

[1943] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 & n.2786 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 87; Order No. 1000, 136 FERC ¶ 61,051 at P 10; *ICC* v. *FERC I,* 576 F.3d at 476).

[1944] *Conn. Light & Power Co.* v. *Nuclear Regul. Comm'n,* 673 F.2d at 533.

[1945] *Telesat Canada* v. *FCC,* 999 F.3d 707, 713 (D.C. Cir. 2021) (quotations omitted).

[1946] Order No. 1920, 187 FERC ¶ 61,068 at PP 1505–1506.

[1947] Clean Energy Associations Rehearing Request at 30–32.

[1948] *Id.* at 31.

[1949] *Id.* at 32–33.

[1950] Dominion Rehearing Request at 26–27.

Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection and does not allocate costs by project type (*i.e.,* reliability, economic, or transmission needs driven by Public Policy Requirements).[1951]

779. In response to Clean Energy Associations' concern that transmission providers could attempt to allocate the costs of two comparable transmission facilities (similar in costs and benefits) using entirely different cost allocation methods if the transmission provider considers them to be different ''types'' of projects (other than those delineated in Order No. 1000's regional cost allocation principle (6)), we note that even if the costs of similar facilities are allocated using different cost allocation methods, the fundamental requirements associated with a just and reasonable rate (*i.e.,* adherence to the cost causation principle and the requirement that costs be allocated in a manner that is at least roughly commensurate with estimated benefits) remain the same.[1952] Therefore, a transmission provider may allocate the costs of two similar transmission facilities using different cost allocation methods and meet the requirements of Order No. 1920. In addition, we note that Order No. 1920 also does not preclude transmission providers from proposing on compliance a cost allocation approach that seeks to maximize net benefits.[1953]

780. Regarding Dominion's request for clarification that if a transmission provider opts to rely on all or some of the seven required benefits in its cost allocation method for Long-Term Regional Transmission Facilities, then it may apply different weighting to different benefits, we note that Order No. 1920 includes no limitation on weighting of the seven required benefits for purposes of accounting for such benefits in the cost allocation method for Long-Term Regional Transmission Facilities save that costs must be allocated in a manner that is at least roughly commensurate with estimated benefits. Further, transmission providers can consider additional benefits for cost allocation purposes, including, but not limited to, those agreed to by Relevant State Entities and those described elsewhere in Order No. 1920, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

H. Additional Cost Allocation Issues

1. Order No. 1920 Requirements

781. In Order No. 1920, the Commission declined to adopt a particular time frame for determining the cost allocation for a Long-Term Regional Transmission Facility. The Commission stated that imposing a standardized time frame to determine cost allocation was unnecessary and could impede the regional flexibility that the Commission provided to transmission providers under Order No. 1920. The Commission added, however, that the determination of the applicable cost allocation must occur by or before selection of a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) if only a Long-Term Regional Transmission Cost Allocation Method is available for that Facility (or portfolio of such Facilities).[1954]

782. Also in Order No. 1920, the Commission stated that, following the 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 using the relevant Long-Term Regional Transmission Cost Allocation Method as a backstop.[1955] Further, in response to NOPR comments requesting that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods, the Commission in Order No. 1920 found 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, and noted that the Commission will evaluate whether a proposed cost allocation method satisfies this standard on a fact-specific basis, relying on the record in a given proceeding. The Commission found that 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.[1956]

783. Separately, in Order No. 1920, the Commission found that commenters' statements regarding cost containment were outside the scope of the proceeding.[1957] The Commission noted that it is examining issues related to transmission planning and cost containment in other proceedings.[1958]

2. Requests for Rehearing and Clarification

784. Dominion seeks clarification regarding the deadline imposed by Order No. 1920's requirement that ''the determination of the applicable cost allocation must occur by or before its selection.'' [1959] Dominion avers that this requirement implies that there could be situations ''when a Long-Term Regional Transmission Facility Cost Allocation Method would not be applied to a Long-Term Regional Transmission Facility.'' [1960] Dominion states that its understanding is that ''a Long-Term Regional Transmission Facility Cost Allocation Method must be used, and that method could be one of several methods: the Transmission Provider's default *ex ante* cost allocation method, some other approved *ex ante* cost allocation method, or a State Agreement Process.'' [1961] Dominion requests that, to the extent the Commission was referring to the deadline of six months after project selection for submission of cost allocation methods resulting from a State Agreement Process, the Commission provide clarification.[1962]

785. Dominion further asks the Commission to clarify whether only the cost allocation method must be determined by project selection, or whether it must be applied (and costs actually allocated) by project selection. Dominion notes its understanding is that only the method must be determined by selection and states that this clarification on timing would help to alleviate the concern about the challenges transmission developers will face in obtaining state regulatory

[1951] Order No. 1920, 187 FERC ¶ 61,068 at PP 1475, 1506. *See supra* P 749.

[1952] Order No. 1920, 187 FERC ¶ 61,068 at P 1305.

[1953] *See id.* P 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.'').

[1954] *Id.* P 1521.

[1955] *Id.* P 1296.

[1956] *Id.* P 1305 (citations omitted).

[1957] *Id.* P 1523. Specifically, the Commission was responding to comments by: (1) Joint Commenters in support of a cost management framework overseen by the Commission; and (2) State Water Contractors, who asserted that the need for cost containment is acute for consumers in California and an essential component of the justness and reasonableness of any final rule. *Id.* P 1518.

[1958] *Id.* P 1523 (citing Supplemental Notice of Technical Conference, Transmission Planning and Cost Management, Docket No. AD22–8–000 (Oct. 4, 2022)).

[1959] Dominion Rehearing Request at 32 (quoting Order No. 1920, 187 FERC ¶ 61,068 at P 1521).

[1960] *Id.* (emphasis omitted).

[1961] *Id.*

[1962] *Id.* at 32–33.

approval for transmission projects designed to meet a predicted need 20 years in the future. Specifically, Dominion states that it is impossible to meet even a ''roughly commensurate'' standard when projected beneficiaries subject to the cost allocation decision are so far removed from the in-service date of the facilities, particularly in the context of an RTO/ISO in which transmission owning entities are permitted to leave and join.[1963]

786. Designated Retail Regulators and Undersigned States argue that any Long-Term Regional Transmission Cost Allocation Method should not include a postage-stamp-type cost allocation, as the costs imposed on non-consenting states should be allocated to cost causers and beneficiaries on as granular a basis as possible. They further argue that postage stamp-type cost allocation method should not be adopted merely to simplify the work of an RTO and to facilitate the construction of such projects.[1964]

787. Wyoming Commission asserts that if a portion of the costs of a Long-Term Regional Transmission Facility are to be recovered from Wyoming retail customers, the Wyoming Commission must evaluate the costs and benefits derived from the project on a *post hoc* basis to determine that costs allocated to retail customers and rates designed to recover those costs are just and reasonable. Wyoming Commission avers that Order No. 1920 does not accommodate this process.[1965]

788. Industrial Customers request rehearing of Order No. 1920's finding that commenters' statements regarding cost containment are outside the scope of this proceeding, arguing that such a finding is arbitrary and capricious because the Commission failed to meaningfully engage arguments and evidence supporting the current need for cost management and cost containment. According to Industrial Customers, while the Commission in Order No. 1920 stated that it is examining issues related to transmission planning and cost containment in other proceedings, Order No. 1920 does not compel the Commission to act in the proceeding in Docket No. AD22–8–000, which is the only pending proceeding that is sufficiently broad to complement Order No. 1920. Industrial Customers add that Order No. 1920 does not demonstrate that cost containment and cost mitigation measures are unrelated to the cost issues at hand or are, in fact, outside the scope of Order No. 1920.[1966]

3. Commission Determination

789. Regarding Dominion's request for clarification regarding the intent of the requirement that ''the determination of the applicable cost allocation must occur by or before its selection,'' [1967] we clarify that this requirement applies only to Long-Term Regional Transmission Cost Allocation Methods. We further clarify that Long-Term Regional Transmission Cost Allocation Methods refer only to *ex ante* cost allocation methods used to allocate the costs of selected Long-Term Regional Transmission Facilities.[1968]

790. Dominion requested clarification as to whether ''the determination of the applicable cost allocation must occur by or before its selection'' [1969] means that only the cost allocation method must be determined by a Long-Term Regional Transmission Facility's selection or whether it must be applied (and costs actually allocated) by project selection. Noting our clarification above that this requirement applies only to Long-Term Regional Transmission Cost Allocation Methods, we clarify that Dominion is correct that only the applicable cost allocation method must be determined by project selection. While it is possible that certain Long-Term Regional Transmission Cost Allocation Methods will be designed in a way that actual costs to be allocated may be known by selection, such a requirement would needlessly limit the flexibility provided to transmission providers and could, in particular, create unnecessary obstacles to transmission providers' ability pursuant to Order No. 1920 to demonstrate that use of existing cost allocation methods to allocate the cost of Long-Term Regional Transmission Facilities would be compliant with Order No. 1920's requirements.[1970]

791. We are not persuaded by arguments raised by Designated Retail Regulators and Undersigned States regarding postage-stamp cost allocation. As in Order No. 1920,[1971] we continue to find that the record does not support a blanket prohibition on postage-stamp-type cost allocation. We will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits on a case-specific basis, relying on the record to ensure that it complies with the cost-causation principle by allocating costs in a manner that is at least roughly commensurate with estimated benefits. We continue to find that the flexibility that we provide to consider benefits in cost allocation does not prevent transmission providers in a particular transmission planning region from adopting a more granular approach.[1972]

792. In response to Wyoming Commission, we reiterate that Order No. 1920 does not change existing mechanisms for cost-recovery through retail rates.[1973] We also emphasize that Order No. 1920 neither aims at nor conflicts with state authority over retail rates.[1974] However, we decline to modify Order No. 1920 to enable states to conduct a *post hoc* review of costs allocated to retail customers. Order No. 1920 does not alter the requirement for states to pass through Commission-jurisdictional rates to retail customers.[1975]

793. Finally, we disagree with Industrial Customers that the Commission failed to engage in reasoned decision making by determining that various NOPR comments regarding cost containment were outside the scope of the proceeding. First, to the extent that Industrial Customers are arguing that the Commission did not consider transmission-related costs to consumers, as noted above, addressing costs to ratepayers was central to the reforms the Commission adopted in Order No. 1920, and the Commission cited evidence that more comprehensive, longer-term regional transmission planning results in the selection of more efficient or cost-effective transmission solutions, which has significant benefits for customers.[1976] Second, the NOPR did not propose to address cost containment reform per se, and we continue to find that certain comments regarding cost containment reform, including those proposing a specific cost management

[1963] *Id.* at 31, 33–34.

[1964] Designated Retail Regulators Rehearing Request at 39; Undersigned States Rehearing Request at 34.

[1965] Wyoming Commission Rehearing Request at 8.

[1966] Industrial Customers Rehearing Request at 21–23 (citing *State Farm,* 463 U.S. at 43).

[1967] Order No. 1920, 187 FERC ¶ 61,068 at P 1521.

[1968] *Id.* P 1291.

[1969] *Id.* P 1521.

[1970] For example, requiring that actual costs be allocated would preclude transmission providers from proposing that DFAX-based or postage-stamp cost allocation methods comply with Order No. 1920 because the amounts each transmission customer will pay are not known at the time of selection for those methods.

[1971] Order No. 1920, 187 FERC ¶ 61,068 at P 1305 (citing Certain TDUs NOPR Initial Comments at 2, 7, 8–9; R Street NOPR Initial Comments at 4, 12).

[1972] *Id.* P 1512.

[1973] *Id.* P 259.

[1974] *Id.* P 998.

[1975] *See Narragansett Elec. Co.* v. *Burke,* 381 A.2d 1358, 1361–63 (R.I. 1977) (holding that the state could not inquire into the reasonableness of the Commission-approved wholesale rate and, consequently, must treat it as a reasonable operating expense in the company's retail cost of service).

[1976] *See supra* The Overall Need for Reform section.

framework, are outside the scope of this proceeding.[1977] Third, we are unpersuaded by Industrial Customers' unsupported argument that the Commission was required to make a binding commitment to finalize cost containment and cost mitigation measures in another docket—we are unaware of any such requirement. Finally, we disagree that Order No. 1920 is arbitrary and capricious because it failed to meaningfully engage with arguments and evidence supporting the need for transmission cost management and cost containment, in contravention of *State Farm*.[1978] *State Farm,* which held that rescission of a prior regulation was arbitrary and capricious because it was done without adequate explanation,[1979] did not hold that every aspect of a problem within an agency's jurisdiction must be addressed in a single rulemaking, or that a final rule must include requirements that address comments that were outside the scope of the proceeding.[1980]

IX. Construction Work in Progress Incentive

A. CWIP

1. Order No. 1920

794. In Order No. 1920, the Commission declined to act to finalize the NOPR proposal 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.[1981] The Commission concluded 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.[1982] The Commission found that, in particular, whether the Commission's incentives are appropriately ''benefitting consumers by ensuring reliability and reducing the cost of delivered power'' is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.[1983]

2. Requests for Rehearing and Clarification

795. Several parties request rehearing on the grounds that the Commission failed to conduct reasoned decision-making in declining to act to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities.[1984] NARUC, for instance, states that the Commission not only failed to rebut arguments that ratepayers will have to pay in advance for facilities that may not ever be used, but also simply declined to finalize the NOPR proposal until the Commission can address other incentives at the same time, which NARUC contends is not reasoned decision-making.[1985] Ohio Consumers agree, and argue that retaining the CWIP Incentive for Long-Term Regional Transmission Facilities without an analysis on the justness and reasonableness of rates of return is arbitrary and capricious.[1986]

796. Some parties argue on rehearing that not adopting the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities will shift risks to ratepayers.[1987] Ohio Consumers state that the failure of the Commission to eliminate the CWIP Incentive for Long-Term Regional Transmission Facilities shifts the risk of long-term transmission planning to consumers who may never benefit from a project if it does not go into service, but who will still be required to pay for it.[1988]

797. Certain parties request that, if the Commission does not grant rehearing in this proceeding and eliminate the CWIP Incentive for Long-Term Regional Transmission Facilities, the Commission should move quickly to address the CWIP Incentive in a separate proceeding.[1989] For instance, Virginia Attorney General implores the Commission to act with expediency to scale back transmission incentives comprehensively in Docket No. RM20–10–000, or another docket as appropriate, if the Commission does not grant rehearing in this proceeding and limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities.[1990]

798. Arizona Commission argues that ''walk[ing] back'' the proposal to disallow the CWIP Incentive is not a logical outgrowth of the NOPR, and failure to provide for additional notice and comment on this ''fundamental'' change is a direct violation of the APA.[1991]

3. Commission Determination

799. We are unpersuaded by arguments raised on rehearing that the Commission erred by failing to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities. We continue to find that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives,[1992] and we disagree with parties that argue that the Commission's decision in Order No. 1920 to defer acting on the CWIP Incentive was arbitrary and capricious. The Commission reviewed all of the comments received on this proposal in response to the NOPR and concluded that whether the Commission's transmission incentives, including the CWIP Incentive, are appropriately ''benefitting consumers by ensuring reliability and reducing the cost of delivered power'' is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.[1993] We continue to reach this conclusion and find that evaluating a single transmission incentive for a regional transmission facility may fail to holistically consider benefits and risks to consumers from transmission incentives.

800. Further, with respect to the argument that the Commission's decision declining to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities was not a logical outgrowth of the NOPR, we disagree. As courts have explained, ''[o]ne logical outgrowth of a proposal is surely . . . to refrain from taking the proposed

[1977] Order No. 1920, 187 FERC ¶ 61,068 at P 1523.

[1978] Industrial Customers Rehearing Request at 23 (citing *State Farm,* 463 U.S. at 43).

[1979] *State Farm,* 463 U.S. at 34.

[1980] *See N.Y.* v. *FERC,* 535 U.S. at 27 (holding that ''[b]ecause FERC determined that the remedy it ordered constituted a sufficient response to the problems FERC had identified in the wholesale market, FERC had no [FPA section] 206 obligation'' to adopt further reforms).

[1981] Order No. 1920, 187 FERC ¶ 61,068 at PP 1524, 1547.

[1982] *Id.* P 1547.

[1983] *Id.* (quoting 16 U.S.C. 824s(a)).

[1984] Industrial Customers Rehearing Request at 24, 26; NARUC Rehearing Request at 5, 8, 10–11; Ohio Consumers Rehearing Request at 11–12.

[1985] NARUC Rehearing Request at 9–11.

[1986] Ohio Consumers Rehearing Request at 12.

[1987] NARUC Rehearing Request at 8–9; Ohio Consumers Rehearing Request at 11; Virginia Attorney General Rehearing Request at 4–5; West Virginia Commission Rehearing Request at 16–17; *see* Designated Retail Regulators Rehearing Request at 42.

[1988] Ohio Consumers Rehearing Request at 11–12.

[1989] Designated Retail Regulators Rehearing Request at 42–43; Industrial Customers Rehearing Request at 28; PJM States Rehearing Request at 9; Virginia Attorney General Rehearing Request at 5; West Virginia Commission Rehearing Request at 17; *see also* Identified Consumer Advocates Rehearing Request at 4, 8–9.

[1990] Virginia Attorney General Rehearing Request at 5.

[1991] Arizona Commission Rehearing Request at 17–19 (citing 5 U.S.C. 706(2)(A), (2)(C), (2)(D)).

[1992] Order No. 1920, 187 FERC ¶ 61,068 at P 1547.

[1993] *Id.* (quoting 16 U.S.C. 824s(a)).

step.'' [1994] The same is true here. We acknowledge the interest and support for evaluating the CWIP Incentive, particularly among several states, along with other transmission incentives, and note that the Commission will continue to evaluate the appropriate manner for considering transmission incentives, including the CWIP Incentive, for all regional transmission facilities.

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

A. Order No. 1920 Requirements

801. In Order No. 1920, the Commission stated that, after careful consideration of the record, it was declining to finalize the NOPR proposal to amend Order No. 1000's findings and nonincumbent transmission developer reforms, in part, to permit the exercise of federal rights of first refusal for selected regional 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. The Commission stated that it will continue to consider potential federal right of first refusal reforms along with other transmission reforms in the future.[1995]

B. Request for Rehearing

802. NRECA states that declining to adopt the NOPR's conditional federal right of first refusal proposal was a missed opportunity because it would have encouraged transmission providers to pursue planning and expanding transmission through joint ownership arrangements with load-serving entities.[1996]

C. Commission Determination

803. The Commission explained in Order No. 1920 that it will continue to consider the NOPR proposal and potential federal rights of first refusal issues in other proceedings, a course of action we continue to find to be reasonable.[1997] As noted in Order No. 1920, comments on the NOPR raised both concerns about whether incumbent transmission providers face perverse investment incentives due to Order No. 1000's reforms and concerns about whether the NOPR proposal would adequately and appropriately address those incentives.[1998]

XI. Local Transmission Planning Inputs in the Regional Transmission Planning Process

A. Need for Reform

1. Order No. 1920

804. In Order No. 1920, the Commission found 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.[1999] Therefore, the Commission adopted the NOPR findings 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.[2000]

805. The Commission explained that 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.[2001] The Commission added that 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.[2002] Additionally, the Commission stated that, while the broader reforms directed in Order No. 1920 are focused on improving the regional transmission planning process, there are discrete deficiencies in the local transmission planning process and its coordination with the regional transmission planning process that must be addressed to ensure Commission-jurisdictional rates are just and reasonable.[2003]

806. The Commission first found that local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders. The Commission recognized the critical role stakeholders serve in effective transmission planning,[2004] and noted prior reforms to facilitate their meaningful participation in both local and regional transmission planning.[2005] However, the Commission found that 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.[2006] The Commission found that the 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.[2007] The Commission explained that 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, the Commission found 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.[2008] The Commission stated that, given the importance of stakeholder participation in effective transmission planning, reforms were needed to ensure that Commission-jurisdictional local and regional transmission planning processes remain just, reasonable, and

[1994] *New York* v. *EPA,* 413 F.3d at 44 (quoting *Am. Iron & Steel Inst.* v. *EPA,* 886 F.2d at 400); *see also Long Island Care,* 551 U.S. at 175 (stating, in the context of rejecting a claim that an agency provided legally defective notice because it did not finalize a proposed rule, ''[w]e do not understand why such a possibility was not reasonably foreseeable''); *Vanda Pharms.,* 98 F.4th at 498 (stating that the APA's ''notice-and-comment procedure is designed so that an agency can float a potential rule to the public without committing itself to enacting the proposed rule's content'').

[1995] Order No. 1920, 187 FERC ¶ 61,068 at PP 1548, 1563–1564.

[1996] NRECA Rehearing Request at 2.

[1997] Order No. 1920, 187 FERC ¶ 61,068 at PP 1563–1564. NRECA did not request rehearing on this issue or include it in NRECA's Statement of Issues. *See* 18 CFR 385.713(c)(2) (any issue not listed in the Statement of Issues will be deemed waived). We nevertheless address NRECA's concern.

[1998] Order No. 1920, 187 FERC ¶ 61,068 at P 1564.

[1999] Order No. 1920, 187 FERC ¶ 61,068 at PP 1565, 1569.

[2000] *Id.* P 1569.

[2001] *Id.* P 1570.

[2002] *Id.* P 1570.

[2003] *Id.* P 1570.

[2004] *Id.* P 1571 (citing Order No. 890, 118 FERC ¶ 61,119 at P 454; Order No. 1000, 136 FERC ¶ 61,051 at P 152).

[2005] *Id.* (citing Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152.).

[2006] *Id.* (citations omitted).

[2007] *Id.*

[2008] P 1572.

not unduly discriminatory or preferential.[2009]

807. The Commission also concluded that additional coordination between the local and regional transmission planning processes regarding the replacement of aging infrastructure is needed. The Commission found that the record showed that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life. The Commission specifically noted that, in PJM and NYISO, a significant portion of transmission assets either need to be replaced or will soon need to be replaced.[2010] The Commission stated that replacing these transmission facilities will require substantial investment, which will directly affect Commission-jurisdictional rates.[2011]

808. The Commission stated, however, that because its 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 system needs.[2012] Therefore, the Commission concluded, 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.[2013]

809. The Commission disagreed with claims from commenters that the Commission lacked jurisdiction to impose the requirements in Order No. 1920 or that the Commission did not justify those requirements.[2014] The Commission explained that consistent with Order Nos. 890 and 1000, the Commission has the authority to establish requirements related to local transmission planning processes and the inputs to regional transmission planning processes.[2015]

810. In response to claims from commenters questioning 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, the Commission explained that it found transmission providers' OATTs to be 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.[2016]

811. Because the Commission found that existing requirements governing transparency in the local transmission planning process and coordination between local and regional transmission planning processes were insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, the Commission required, pursuant to FPA section 206, transmission providers to adopt, with modifications, the two reforms the Commission identified in the NOPR: (1) enhance the transparency of the local transmission planning process; 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.[2017] The Commission found 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. The Commission found 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. Finally, the Commission found that, taken together, these reforms will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[2018]

812. On rehearing, several parties challenge the Commission's findings. We address their arguments below.

2. Analysis Under FPA Section 206

a. Rehearing Requests

813. Advanced Energy and Competition Coalition contend that the Commission failed to engage in reasoned decision-making, in violation of the APA and the required analysis under FPA section 206, by ignoring relevant considerations, failing to address applicable precedent, and inadequately explaining its decision to grant incumbent transmission providers a right of first refusal for right-sized replacement transmission facilities.[2019] Competition Coalition adds that the Commission has failed to prove that the reform is just and reasonable, supported by substantial evidence, the product of reasoned decision-making, and consistent with the public interest.[2020]

814. Competition Coalition, Industrial Customers, and Designated Retail Regulators request rehearing on the grounds that, in adopting the reforms in Order No. 1920 regarding enhanced transparency of local transmission planning inputs and identifying opportunities to right-size replacement transmission facilities, the Commission failed to satisfy the requirement to make a finding, supported by substantial evidence, that the existing relevant tariff provisions result in rates that are unjust, unreasonable, or unduly discriminatory.[2021] Competition Coalition and Industrial Customers, for example, argue that Order No. 1920 does not support with substantial evidence the Commission's claim that the interrelationship between local and regional transmission planning yields unjust, unreasonable, or unduly discriminatory rates, and therefore does not reflect reasoned decision-making.[2022] Similarly, Designated Retail Regulators argue that the Commission failed to provide an analysis of the justness and reasonableness of the local transmission planning processes as a prerequisite to adopting the local transmission planning and right-sizing

[2009] *Id.*

[2010] *Id.* P 1573 (citations omitted).

[2011] *Id.*

[2012] *Id.* P 1574.

[2013] *Id.* P 1574.

[2014] *Id.* P 1575 (citations omitted).

[2015] *Id.* (citing Order No. 890, 118 FERC ¶ 61,119 at P 435; Order No. 1000, 136 FERC ¶ 61,051 at PP 68, 148, 1520).

[2016] *Id.* P 1576 (citations omitted).

[2017] *Id.* P 1577.

[2018] *Id.*

[2019] Advanced Energy Rehearing Request at 4; Competition Coalition Rehearing Request at 8.

[2020] Competition Coalition Rehearing Request at 59–60.

[2021] Competition Coalition Rehearing Request at 14 (citing *Emera Maine* v. *FERC,* 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*)); Industrial Customers Rehearing Request at 4–5; Designated Retail Regulators Rehearing Request at 7, 41.

[2022] Competition Coalition Rehearing Request at 14; Industrial Customers Rehearing Request at 4–5.

reforms in Order No. 1920.[2023] Competition Coalition contends that Order No. 1920's findings on encouraging transmission providers to provide their best in-kind replacement estimates and removing other disincentives do not provide a basis for satisfying the first prong of FPA section 206.[2024]

815. Several parties separately assert that the Commission failed to satisfy the first prong of FPA section 206 when it adopted the federal right of first refusal requirement for right-sized replacement transmission facilities.[2025] Competition Coalition contends, and Industrial Customers agree, that Order No. 1920 fails to identify the specific regional transmission planning and cost allocation tariff requirements, particularly those that relate to in-kind replacement processes, that are unjust, unreasonable, or unduly discriminatory or preferential as a result of the lack of an incumbent preference.[2026] Rather, Competition Coalition argues, the identified concern—lack of transparency in local transmission planning as an input to regional transmission planning—has nothing to do with the lack of a right of first refusal in the regional transmission planning process.[2027] Competition Coalition further states that the absence of any nexus between the identified problem in Order No. 1920—that existing regional transmission planning processes are unjust and unreasonable—and the prescribed remedy is glaring as it concerns the federal right of first refusal for right-sized replacement transmission facilities.[2028]

816. Competition Coalition also asserts that Order No. 1920 fails to provide substantial evidence that the existing regional transmission planning framework as it relates to incumbent public utility preferences for regionally planned, regionally cost allocated projects in existing transmission provider tariff provisions is unjust, unreasonable, or unduly discriminatory or preferential. Competition Coalition also contends that Order No. 1920 does not elaborate on, or support with substantial evidence, the reference to "coordination" in the context of its finding under the first prong of FPA section 206.[2029] Competition Coalition states that substantial evidence is "relevant evidence that a reasonable mind might accept as adequate to support a conclusion." [2030]

b. Commission Determination

817. We sustain the finding in Order No. 1920 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.[2031] We continue to find that Order No. 1920's reforms to transparency in local transmission planning inputs and coordination between local and regional transmission planning processes are necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.

818. We disagree with Competition Coalition and Advanced Energy that the Commission failed to satisfy the required analysis of FPA section 206 in adopting the reforms to enhance the transparency of local transmission planning inputs and coordination between the local and regional transmission planning processes. As the Commission noted in Order No. 1920, 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.[2032] Further, we continue to find that local and regional transmission planning processes serve essential and complementary roles in ensuring that customers' transmission needs are identified and met at just and reasonable rates, including through the identification, evaluation, and selection of more efficient or cost-effective transmission solutions through regional transmission planning.[2033] As the Commission stated in Order No. 1920, information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning.[2034]

819. The Commission supported its findings in Order No. 1920 with comments and studies in the record highlighting that the lack of transparency and coordination requirements in local transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.[2035] Specifically, the Commission also found that additional coordination between the local and regional transmission planning processes regarding the replacement of aging infrastructure is needed, especially in light of the record evidence that incumbent transmission providers across the country are replacing aging transmission infrastructure as it reaches the end of its useful life [2036] without considering whether a regional transmission solution could be more efficient or cost-effective. Ultimately, the Commission concluded, based on these findings, that the existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes were unjust, unreasonable, and unduly discriminatory or preferential.[2037]

820. We also disagree with arguments raised by Competition Coalition, Industrial Customers, and Designated Retail Regulators that the Commission's findings under FPA section 206 are not supported by substantial evidence and find that Competition Coalition's reliance on *Emera Maine* is misplaced.[2038] Rehearing parties' arguments on this issue ignore the Commission's extensive explanation of the circumstances that have rendered the existing rates and practices affecting those rates unlawful.[2039] The Commission first identified a lack of adequate provisions for transparency and meaningful input from stakeholders within local transmission planning processes.[2040] In support of this finding, the Commission: (1) cited prior final rules recognizing stakeholders' critical role in effective transmission planning; and (2) found that those prior final rules required reforms to provide for stakeholders' meaningful participation in both local and regional transmission planning processes.[2041]

821. The Commission next identified the lack of a requirement for transmission providers in each transmission planning region to

[2023] Designated Retail Regulators Rehearing Request at 7.

[2024] Competition Coalition Rehearing Request at 18.

[2025] *Id.* at 6, 11–19, 36–37; Industrial Customers Rehearing Request at 13–15.

[2026] Competition Coalition Rehearing Request at 12–13; Industrial Customers Rehearing Request at 12–13.

[2027] Competition Coalition Rehearing Request at 13.

[2028] *Id.* at 13.

[2029] *Id.* at 13–14.

[2030] *Id.* at 9.

[2031] Order No. 1920, 187 FERC ¶ 61,068 at P 1569.

[2032] *Id.* P 1572; *see also id.* P 109.

[2033] *Id.* P 1570.

[2034] *Id.*

[2035] *Id.* P 1571.

[2036] *Id.* P 1573, nn.3363–3365.

[2037] *Id.* PP 1573–1574, 1576.

[2038] *See Emera Maine* v. *FERC,* 854 F.3d 9 (D.C. Cir. 2017).

[2039] *Id.* PP 1571, 1572.

[2040] *Id.* P 1571.

[2041] *Id.* P 1571 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152).

evaluate whether replacement transmission facilities could be modified (*i.e.,* right-sized) to more efficiently or cost-effectively address transmission needs. As noted above, the Commission highlighted evidence from the record that, for example, PJM and NYISO anticipate soon replacing a substantial portion of their aging transmission infrastructure as it reaches the end of its useful life, which will directly affect Commission-jurisdictional rates.[2042] Based on this evidence, the Commission concluded that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes 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.[2043] We therefore conclude that the Commission found, based on substantial evidence, that these requirements are unjust, unreasonable, or unduly discriminatory, and determined that the identified deficiencies must be addressed to ensure that Commission-jurisdictional rates are just and reasonable.

822. Order No. 1920 also pointed out that the federal right of first refusal for selected right-sized replacement transmission facilities will provide transmission providers with 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, and this, in turn, will encourage transmission providers to provide their best in-kind replacement estimates.[2044] Accordingly, the Commission found that that a federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning. The Commission added that this will help to ensure that transmission providers identify and select the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs.[2045]

823. As Competition Coalition points out in its rehearing request, substantial evidence is ''relevant evidence that a reasonable mind might accept as adequate to support a conclusion.'' [2046] The above discussion makes clear that the Commission examined the relevant data and articulated a rational connection between the facts found and the choices made in enacting the reforms in Order No. 1920. We thus continue to find that the Commission engaged in reasoned decision-making and considered all important aspects of the problem and meaningfully responded to the arguments raised before it.

3. Departure From Commission Precedent

a. Rehearing Requests

824. Competition Coalition opines that no explanation can be offered for how the right-sizing proposal is not in conflict with FPA section 206 because Order Nos. 1000 and 1000–A required the elimination of federal rights of first refusal.[2047] Competition Coalition also asserts that Order No. 1920 departs from Commission precedent without explanation.[2048]

b. Commission Determination

825. We are unpersuaded by Competition Coalition's argument that Order No. 1920 does not provide a reasoned explanation regarding Order No. 1920's departure from Order Nos. 1000 and 1000–A in establishing a federal right of first refusal for right-sized replacement transmission facilities. In Order No. 1920, the Commission recognized 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. The Commission then found that requiring a federal right of first refusal for right-sized replacement transmission facilities aligns with Order No. 1000.[2049] The Commission explained that, in Order No. 1000, transmission providers were required 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.[2050] The Commission also explained that, in Order No. 1000, it 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.[2051]

826. The Commission further explained that Order No. 1000 did not require the elimination of federal rights of first refusal for local transmission facilities, nor did it alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to their own transmission facilities, regardless of whether the upgrade is selected in the regional transmission plan for the purposes of cost allocation.[2052] Because 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 also 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, which includes the need for replacements of existing transmission facilities via local transmission planning processes, the Commission concluded that the reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities.[2053] Specifically, Order No. 1920 found that 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, the Commission found that a federal right of first refusal will promote the consideration of more efficient or cost-effective potential

[2042] *Id.* P 1573, nn.3363–3365.

[2043] *Id.* P 1574.

[2044] *Id.* P 1703; *see infra* Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities section. The Commission defined ''in-kind replacement estimates'' as ''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 . . . .'' Order No. 1920, 187 FERC ¶ 61,068 at P 1677. We clarify that these estimates include, at minimum, identification of the transmission facilities themselves.

[2045] *See infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2046] Competition Coalition Rehearing Request at 9 (citing *N.J. Bd. of Pub. Utils.* v. *FERC,* 744 F.3d 74, 94 (3d Cir. 2014)) (citing Mars Home for Youth v. NLRB, 666 F.3d 850, 853 (3rd Cir. 2011).

[2047] Competition Coalition Rehearing Request at 36–37 (citing *S. C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 71–76).

[2048] *Id.* at 37 n.112, 40.

[2049] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

[2050] *Id.* P 1705; *infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2051] Order No. 1920, 187 FERC ¶ 61,068 at P 1705 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 257).

[2052] *See id.* P 1705 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 319.)

[2053] *Id.* P 1706; *see infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

regional transmission solutions to address Long-Term Transmission Needs because it captures both an individual transmission provider's responsibilities and a Long-Term Transmission Need, we believe the right-sizing reform preserves transmission providers' ability to invest in replacements of their own transmission facilities, even if such facilities are right-sized and selected in the regional transmission plan for purposes of cost allocation.[2054] Furthermore, the Commission noted that the reasons for removing federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities because transmission providers may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing their transmission facilities.[2055]

827. We therefore continue to find that providing for a federal right of first refusal for right-sized replacement transmission facilities aligns with the text and stated purpose of Order No. 1000 by ensuring that transmission providers consider more efficient or cost-effective regional transmission solutions.[2056] We also reaffirm that the right-sizing reform does not depart, without explanation, from Commission precedent related to an individual transmission provider's ability to proceed with an in-kind replacement transmission facility. Further, we believe that, without a federal right of first refusal, the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely opt to develop the less efficient or cost-effective in-kind replacement transmission facility rather than a right-sized replacement transmission facility.[2057] Therefore, we continue to find that the establishment of the federal right of first refusal for right-sized replacement transmission facilities that are evaluated and selected as part of Long-Term Regional Transmission Planning is necessary to effectuate this reform and ensure that Commission-jurisdictional rates are just and reasonable.[2058] As the Commission reasoned in Order No. 1920, by establishing a process that requires transmission providers to evaluate opportunities to right-size in-kind replacement transmission facilities to meet transmission needs, the right-sizing reform 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. The Commission concluded that together, these reforms will enable transmission providers to ensure that the more efficient or cost-effective regional solution to transmission needs is identified, evaluated, and selected, and therefore that Commission-jurisdictional rates are just and reasonable.

4. Commission Authority Under the FPA

a. Rehearing Requests

828. Competition Coalition argues that FPA section 206 cannot support the Commission's adoption of a monopoly preference when FPA section 206 mandates the opposite result (prohibition on unduly discriminatory or preferential rates or practices affected rates).[2059] Advanced Energy argues that the FPA lacks a plausible textual basis for the Commission to bestow on the incumbent utilities a ''monopoly right'' to develop and own certain types of transmission infrastructure.[2060] Thus, Advanced Energy and Competition Coalition assert, the Commission exceeded its authority under FPA section 206.[2061]

829. Both Advanced Energy and Competition Coalition assert that the Commission's application of FPA section 206 is inconsistent with U.S. Supreme Court precedent.[2062] Advanced Energy states that the Commission's reliance on FPA section 206 to bestow a federal right of first refusal raises serious constitutional questions and, therefore, is inconsistent with the constitutional-doubt canon of statutory construction.[2063] Advanced Energy claims that since FPA section 206 contains no explicit language regarding development or ownership of transmission facilities or authorizing the establishment of a federal right of first refusal, relying on FPA section 206 to adopt the right-sizing reform calls into question whether Congress delegated such authority to the Commission and, if so, whether that delegation was proper.[2064]

830. Advanced Energy states that, in enacting FPA section 216, Congress reinforced the FPA's longstanding jurisdictional framework that the Commission does not possess the authority to prevent ''any person'' from constructing or modifying a transmission facility.[2065] Advanced Energy argues that, as a result, the Commission exceeded its authority under the FPA by granting incumbents a right of first refusal to develop and own right-sized replacement transmission facilities, to the exclusion of all others.[2066] Similarly, Competition Coalition attests that Order No. 1920 failed to demonstrate that the Commission has the legal authority under the FPA to mandate the federal right of first refusal of transmission facilities, and further argues that the FPA provides the Commission no authority to do so.[2067] Undersigned States argue that right-sizing intrudes upon state authority.[2068]

b. Commission Determination

831. We disagree with Advanced Energy's, Competition Coalition's, and Undersigned States' arguments that the reforms in this section, specifically the right-sizing reform and the federal right of first refusal for right-sized replacement transmission facilities, exceed the Commission's authority.[2069] The Commission's authority under FPA section 201 includes ''the transmission of electric energy in interstate commerce,'' and under FPA section 206 the Commission's authority is to ensure that practices affecting Commission-jurisdictional rates are just and reasonable.[2070] As explained in *EPSA,* this jurisdiction extends to practices that ''directly affect'' such rates.[2071] The

[2054] *See infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2055] Order No. 1920, 187 FERC ¶ 61,068 at PP 1706–1707; *see infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2056] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

[2057] *See infra* Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected to Meet Long-Term Transmission Needs section.

[2058] Order No. 1920, 187 FERC ¶ 61,068 at PP 1706–1707.

[2059] Competition Coalition Rehearing Request at 36.

[2060] Advanced Energy Rehearing Request at 5, 6–7 (citing 16 U.S.C. 824e(a)).

[2061] *Id.* at 5, 8; Competition Coalition Rehearing Request at 22–23.

[2062] Advanced Energy Rehearing Request at 8–10 (citing *West Virginia,* 597 U.S. at 721, 723, 730; *Whitman* v. *Am. Trucking Ass'ns,* 531 U.S. at 468); Competition Coalition Rehearing Request at 36 (citing *West Virginia,* 597 U.S. at 723).

[2063] Advanced Energy Rehearing Request at 10 (citing Antonin Scalia & Bryan A. Garner, *Reading Law: The Interpretation of Legal Texts* 247–48 (2012) (citing *Crowell* v. *Benson,* 285 U.S. 22, 62 (1932))).

[2064] *Id.* at 10, 21 (citing *West Virginia,* 597 U.S. 697).

[2065] *Id.* at 8 (citing 16 U.S.C. 824p(g)).

[2066] *Id.* at 5, 8.

[2067] Competition Coalition Rehearing Request at 7, 21–23.

[2068] Undersigned States Rehearing Request at 36.

[2069] *See* Advanced Energy Rehearing Request at 4–12; Competition Coalition Rehearing Request at 7, 20–40; Undersigned States Rehearing Request at 36.

[2070] *See supra* Federal/State Division of Authority section.

[2071] 577 U.S. at 278.

federal right of first refusal acknowledges existing precedent recognizing state laws providing an individual transmission provider's ability to proceed with an in-kind replacement transmission facility and encourages transmission providers to provide their best in-kind replacement estimates by preserving the transmission providers' ability to invest in facilities selected as right-sized replacement transmission facilities.[2072] The Commission explained that the establishment of a federal right of first refusal in this regard will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address transmission needs.

832. Indeed, rights of first refusal have generally been found to be practices affecting rates, thus confirming that they are within the Commission's jurisdiction—albeit in the context of their removal.[2073] Thus, the Commission's action in Order No. 1920 is entirely consistent with Order No. 1000 in that respect. Advanced Energy and Competition Coalition fail to recognize the inherent contradiction in their arguments. When addressing our statutory authority, the relevant question is whether the Commission can regulate rights of first refusal, not how it chooses to regulate them. The claim that the establishment of a federal right of first refusal for right-sized replacement transmission facilities is beyond the Commission's authority is squarely contrary to Order No. 1000 and *South Carolina*.[2074]

833. We are unpersuaded by arguments that the Commission lacks authority under the FPA to require the right-sizing reform. FPA section 206 provides the Commission with the authority to determine the just and reasonable rate following a finding that any rate, charge, regulation, or practice is unjust, unreasonable, unduly discriminatory or preferential. The D.C. Circuit has recognized that regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction [2075] and that 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.[2076]

834. We also are unpersuaded by Advanced Energy's and Competition Coalition's claims that the right of first refusal for right-sized replacement transmission facilities requires explicit congressional authorization and find that, notwithstanding references to *West Virginia* in their rehearing requests, the major questions doctrine is not implicated here. As discussed in detail above,[2077] the major questions doctrine is a context-specific analysis that applies only in ''extraordinary cases'' where an agency action is so extravagant that it is akin to discovering an ''elephant in a mousehole.'' [2078] More specifically, the major questions doctrine comes into play where, despite a ''colorable textual basis'' for the agency's claim of authority, the agency action was so extravagant when viewed in light of the statutory context that it was unlikely that Congress would have afforded this claimed authority to the agency, and particularly would not have done so in an oblique or subtle way.[2079]

835. The Advanced Energy and Competition Coalition rehearing requests do not meaningfully engage with the context-specific factors associated with the application of the major questions doctrine. Advanced Energy's theory that the doctrine applies boils down to its characterization of the federal right of first refusal as a ''monopoly franchise right'' and assertion that replacing transmission projects is extremely expensive.[2080] Competition Coalition similarly relies on a largely conclusory invocation of *West Virginia,* without analysis beyond asserting that this is an ''extraordinary case'' because the Commission has never previously asserted that Congress granted it this power.[2081]

836. We continue to conclude that the major questions doctrine does not apply to Order No. 1920, which is a rulemaking under the Commission's broad authority over transmission planning processes affecting Commission-jurisdictional rates. Specifically, here, Order No. 1920's inclusion of a federal right of first refusal for right-sized replacement transmission facilities falls well within the Commission's authority under FPA section 206 over ''practice[s] . . . affecting'' rates, the same grant of statutory authority supporting issuance of Order No. 1920.[2082] As a result, for all the reasons that we find that the major questions doctrine is inapplicable to Order No. 1920 as a whole,[2083] we likewise find that Advanced Energy and Competition Coalition have not shown that the major questions doctrine applies to Order No. 1920's inclusion of a federal right of first refusal for right-sized replacement transmission facilities.

837. We are also unpersuaded by Advanced Energy's claims that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities raises constitutional questions and is therefore inconsistent with the constitutional-doubt canon of statutory construction.[2084] Advanced Energy does not discuss the substance of this doctrine, cite any authority that relates to this doctrine, or explain how—by authorizing the Commission to regulate practices affecting rates, which includes the local transparency improvements and the right-sizing reform—Congress would have impermissibly delegated legislative power to the Commission.[2085]

838. We also disagree with Advanced Energy that the Commission exceeded its authority under FPA section 216 and find such arguments to be misplaced. FPA section 216 governs the Commission's authority with respect to authorization of a construction permit for a transmission facility located within a National Interest Electric Transmission Corridor under certain circumstances. FPA section 216 does not alter or restrict the Commission's authority to identify a replacement rate under section 206 of the FPA, including the provision for or the removal of a federal right of first refusal, to ensure transmission providers' OATTs are just and reasonable and not unduly discriminatory or preferential. The

[2072] Order No. 1920, 187 FERC ¶ 61,068 at P 1707.

[2073] *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 72.

[2074] *Id.* at 73–76 (finding that the Commission was authorized to regulate the right of first refusal provisions in Commission-jurisdictional tariffs and that the Commission correctly concluded that inclusion of rights of first refusal in tariffs and agreements was a ''practice affecting a rate triggering the Commission's authority under FPA section 206.'').

[2075] Order No. 1920, 187 FERC ¶ 61,068 at P 86 (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 at 55–59, 84; *see* Order No. 1000–A, 139 FERC ¶ 61,132 at P 577).

[2076] *Id.* (citing *S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d at 56).

[2077] *See supra* Major Questions Doctrine section.

[2078] *See West Virginia,* 597 U.S. at 746.

[2079] *Id.* at 722–23.

[2080] Advanced Energy Rehearing Request at 9–10.

[2081] Competition Coalition Rehearing Request at 34, 36.

[2082] *See EPSA,* 577 U.S. at 277–78; *S.C. Pub. Serv. Auth.* v. *FERC,* 762 at 56–57; *CAISO,* 372 F.3d at 399–404.

[2083] *See supra* Major Questions Doctrine section.

[2084] *See* Advanced Energy Rehearing Request at 10 (citing Antonin Scalia & Bryan A. Garner, *Reading Law: The Interpretation of Legal Texts,* at 247–48 (2012) (citing *Crowell* v. *Benson,* 285 U.S. at 62)).

[2085] *Id.; see also supra* Major Questions Doctrine section.

federal right of first refusal for right-sized replacement transmission facilities is not aimed at, nor does it directly regulate, an area of state authority.[2086] As discussed in Order No. 1920 and above, the Commission is not unlawfully supplanting state authority, including siting and development processes.[2087] States retain their authority over those processes and the federal right of first refusal for right-sized replacement transmission facilities is not directed at those practices nor does it divest states of their authority. As explained above, the right-sizing processes, including the right of first refusal for right-sized replacement transmission facilities, are directed at Commission-jurisdictional transmission planning processes.

839. We are not persuaded by Advanced Energy's acontextual reading of FPA section 216(g) which posits that—in providing backstop siting authority to the Commission under FPA section 216 and allowing the Commission, in certain circumstances, to grant construction permits for transmission facilities within designated National-Interest Electric Transmission Corridors—Congress was subtly intending to negate the Commission's authority in FPA sections 205 or 206, particularly with respect to the right-sizing rights of first refusal or rights of first refusal more generally. The far more natural interpretation of this provision is that it means what it says, clarifying the impact of ''this section'' of the FPA: that despite creating such backstop permitting authority residing with the Commission, FPA section 216 does not preclude the construction or modification of transmission facilities in accordance with state law.[2088]

5. Policy Against Anticompetitive Practices

a. Rehearing Requests

840. Both Competition Coalition and Advanced Energy claim that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities is inconsistent with federal policy against anticompetitive practices.[2089] Specifically, Advanced Energy asserts that the federal right of first refusal is inconsistent with Supreme Court finding that ''the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest.'' [2090] Competition Coalition contends that the reform is contrary to appellate courts' affirmation that monopoly preferences are against the public interest.

b. Commission Determination

841. Order No. 1920's conclusion that the federal right of first refusal for right-sized replacement transmission facilities is within the Commission's authority is further supported by the history and context of the FPA broadly, and rights of first refusal generally—contrary to the arguments in the rehearing requests. As the Supreme Court has recognized, electric utilities have historically been vertically integrated monopolies, including as to transmission.[2091]

842. When Congress enacted the FPA, it charged the Commission with ensuring that rates and practices were ''just and reasonable'' and not unduly discriminatory or preferential. Within these parameters, the statutory text does not require a particular approach. Thus, Advanced Energy's and Competition Coalition's invocation of a policy against anticompetitive practices is unpersuasive.[2092] The Commission's authority is defined and delineated by the FPA, not by reference to a general policy that may favor competition. Notably, the case Advanced Energy cites in this context, *Otter Tail,* did not address the Commission's authority under FPA section 205 or 206, and instead considered whether provisions of the FPA implicitly repealed otherwise applicable antitrust laws.[2093]

6. Other Arguments

a. Rehearing Requests

843. Competition Coalition asserts that Order No. 1920 fails to meaningfully engage with NOPR arguments and rebut arguments presented in those comments. Competition Coalition also asserts that the phrase federal rights of first refusal is a ''made-up phrase'' that has no history in the FPA.[2094] Competition Coalition adds that the federal right of first refusal for right-sized replacement transmission facilities is likely to encourage gaming.[2095]

b. Commission Determination

844. We also find that Competition Coalition's remaining arguments are unpersuasive as they fail to engage with the statutory text or context and, ultimately, have little to do with the Commission's statutory authority, notwithstanding how they are categorized in Competition Coalition's rehearing request.

845. A large swath of Competition Coalition's arguments discuss the history of the phrase ''federal right of first refusal,'' arguing that ''the phrase was nothing more than a made-up general reference for clauses in [Commission]-jurisdictional contracts or tariffs implemented by existing transmission owners to impede independent transmission developers seeking to develop cost-of-service transmission.'' [2096] We find that this discussion has little bearing on the issue of the Commission's authority, which is defined by the statutory text and relevant precedent construing this text. As discussed above, we find that establishing the federal right of first refusal for right-sized replacement transmission facilities is within our authority and consistent with that history. We also note that Order No. 1000 did not require the removal of all rights of first refusal. Thus, Order No.1000 does not suggest that establishment of a federal right of first refusal for right-sized replacement transmission facilities is beyond the Commission's authority.

846. We also find that most of Competition Coalition's other arguments—although housed in a portion of their request for rehearing contending that Order No. 1920 exceeds the Commission's statutory authority—are mislabeled. On their substance, these arguments amount to disputes over whether the federal right of first refusal for right-sized replacement transmission facilities is just and reasonable and not unduly discriminatory or preferential and whether the Commission departed from

[2086] *See supra* Federal/State Division of Authority section (explaining that Commission regulations are not unlawful even if they substantially affect areas of reserved state jurisdiction so long as the Commission is directly regulating within its areas of authority under the FPA, rather than attempting to directly regulate within state jurisdiction).

[2087] *See supra* Federal/State Division of Authority section; *See also* Order No. 1920, 187 FERC ¶ 61,068 at P 271.

[2088] We note, further, that Order No. 1920 is not a regulation under FPA section 216 and no part of the right-sizing right of first refusal relies on Commission authority under FPA section 216.

[2089] Competition Coalition Rehearing Request at 67–68 (citing Exec. Order No. 14,036, 3 CFR 100.1); Advanced Energy Rehearing Request at 10–11.

[2090] Advanced Energy Rehearing Request at 10–11 (citing *Otter Tail* v. *U.S.,* 410 U.S. 366, 374 (1973)).

[2091] *Morgan Stanley Cap. Grp. Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash.,* 554 U.S. 527, 535–36 (2008) (finding that, historically, electric utilities have been monopolies).

[2092] Advanced Energy Rehearing Request at 10–11.

[2093] *See id.* at 10 n.30.

[2094] Competition Coalition Rehearing Request at 24–29.

[2095] *Id.* at 61, 68–71.

[2096] *Id.* at 24–29 (arguing that such provisions were not based on requirements of the FPA or rights inherent in the FPA).

its precedent without adequate explanation, albeit peppered with assertions that the federal right of first refusal for right-sized replacement transmission facilities is not supported by the FPA.[2097] Throughout this order, we affirm that the replacement rate set by the Commission in Order No. 1920 is just and reasonable and not unduly discriminatory.[2098] We find that the Commission's authority is plainly stated in FPA section 206 to evaluate rates and practices to determine whether they are unjust and unreasonable or unduly discriminatory or preferential, and, if so, prescribe a replacement rate that is just and reasonable and not unduly discriminatory or preferential. On its face, the federal right of first refusal for right-sized replacement transmission facilities is an exercise of that authority, as discussed above.

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

1. Order No. 1920

847. In Order No. 1920, the Commission required transmission providers 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.[2099] Specifically, the Commission required 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.[2100] The Commission stated that the requirement to establish this process ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process.[2101] The Commission also clarified that these requirements applied 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, the Commission stated, this requirement does not apply to asset management projects.[2102]

848. The Commission required 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).[2103] Furthermore, the Commission required that 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).[2104] Finally, the Commission required that, 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).[2105]

849. Additionally, the Commission required that the materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.[2106] Specifically, the Commission required 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.[2107] The Commission also required 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.[2108] Lastly, the Commission required 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.[2109]

850. In Order No. 1920, the Commission declined to adopt alternatives requested by commenters to this set of reforms because such proposals were not included in the NOPR and, as a result, the requests were beyond the scope of the proceeding.[2110] The Commission noted, however, that several of these issues may be examined in the Commission's ongoing Transmission Planning and Cost Management proceeding.[2111]

2. Requests for Additional Reforms

a. Requests for Rehearing and Clarification

851. Several parties request rehearing of the Commission's decision to exclude asset management projects from the local transmission planning

[2097] *See id.* at 32–40 (arguing that Order No. 1920 departs from the approach of previous Commission orders seeking to curtail transmission provider self-interest and challenging the Commission's rationale for adopting the federal right of first refusal for right-sized replacement transmission facilities); *id.* at 35–36 (arguing that the rationale of *Orangeburg, S.C.* v. FERC, 862 F.3d 1071 (2017), and the Commission's findings in Order No. 1000, require the elimination of disparate treatment of nonincumbent transmission providers); *id.* at 36–40 (arguing that FPA section 206 requires ''elimination of preferential rates or practices affecting rates'' and that the federal right of first refusal for right-sized replacement transmission facilities is inconsistent with this requirement, that the Commission cannot ''ignore its prior declaration that rights of first refusal are unduly discriminatory or preferential,'' and that Order No. 1920 is disingenuous in distinguishing precedent or claiming that it is not creating a ''new preference''); *cf. id.* at 29–32 (discussing Order Nos. 1000 and 1000–A, arguing that because the Commission rejected ''monopoly preference provisions'' in those orders, even applying a heightened contract review, there is ''no support for an assumption that the Commission enjoys Congressionally granted authority to simply create a federally sanctioned 'cartel-like' monopoly preference'').

[2098] *See supra* The Commission Demonstrated that the Replacement Rate is Just and Reasonable section.

[2099] Order No. 1920, 187 FERC ¶ 61,068 at P 1625.

[2100] *Id.* P 1626.

[2101] *Id.*

[2102] *Id.* P 1625 (citing *S. Cal. Edison Co.,* 164 FERC ¶ 61,160, at PP 30–40 (2018); *Cal. Pub. Utils. Comm'n* v. *Pac. Gas. & Elec. Co.,* 164 FERC ¶ 61,161, at PP 65–74 (2018) (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)).

[2103] *Id.* P 1627.

[2104] *Id.*

[2105] *Id.*

[2106] *Id.*

[2107] *Id.* P 1628.

[2108] *Id.*

[2109] *Id.*

[2110] *Id.* P 1648.

[2111] Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22–8–000 (Apr. 21, 2022).

transparency requirements in the final rule.[2112] Old Dominion states that the Commission failed to address the lack of meaningful transparency in local transmission planning by deciding to exclude asset management projects from the local transmission planning transparency requirements, which it argues is an error that will perpetuate unjust and unreasonable rates.[2113] Further, Old Dominion contends that the Commission's assertion that there is not sufficient record evidence or that it would be outside the scope of the proceeding to adopt reforms that were not proposed in the NOPR is unreasonable and inconsistent with other aspects of the final rule where the Commission adopted proposals that were neither supported by sufficient record evidence nor included in the NOPR.[2114] Old Dominion states that if the Commission does not grant rehearing on this issue, then the Commission should undertake further reforms for local transmission planning, such as in Docket No. AD22–8–000.[2115]

852. NESCOE states that the Commission's decision to exclude asset management projects [2116] from the scope of the local transmission planning transparency enhancements does not constitute reasoned decision-making, because the final rule does not sufficiently address concerns that asset condition projects are not subject to sufficient transparency, scrutiny, and review requirements.[2117] NESCOE further argues that, despite the Commission's acknowledgement that reforms are needed to ensure regional transmission planning and cost allocation are just and reasonable, the Commission's failure to adopt such reforms based on a single-sentence rationale demonstrates that the Commission has not ''made a reasoned decision based upon substantial evidence in the record,'' nor has it ''articulate[d] a satisfactory explanation for its action including a rational connection between the facts found and the choice made.'' [2118] NESCOE argues that the exemption of asset management projects from the local transmission planning transparency requirements results in a regulatory gap where transmission costs are unreviewed at both the state and federal level.[2119] NESCOE contends that this is a particularly acute concern in New England where, since February 2023, transmission owners have brought $3.3 billion in asset management projects through ISO–NE's Planning Advisory Committee.[2120]

853. Ohio Commission Federal Advocate argues that the Commission's adoption of ''perfunctory'' transparency reforms for local planning processes was arbitrary and capricious, and will do nothing to close the regulatory gap or provide oversight for local projects.[2121] Ohio Commission Federal Advocate notes that given the increasing portion of transmission facilities that are considered ''supplemental projects'' [2122] in PJM, the reforms adopted in Order No. 1920 do little to shift the scales and the reforms may increase the portion of the transmission system built through a local transmission planning process.[2123] As such, Ohio Commission Federal Advocate contends that the Commission neglected its duty under the FPA to ensure just and reasonable rates by imposing reforms that will not curb rising transmission costs or result in holistic transmission planning.[2124]

854. Industrial Customers request rehearing and argue the Commission failed to engage requests that call for implementation of an independent transmission monitor. Given the increase in spending on transmission projects, Industrial Customers argue that clarifying or expanding existing independent market monitor functions or creating an independent transmission monitor would be a timely and appropriate exercise of the Commission's authority to remedy unjust and unreasonable rates.[2125] Moreover, Industrial Customers contend that Order No. 1920 falls short of ensuring just and reasonable rates because it does not undertake reforms of transmission formula rates or the Commission's prudence standard.[2126] Industrial Customers argue that since Order No. 1920 failed to implement any concrete reforms to protect consumers, rehearing is warranted.[2127]

855. PIOs request rehearing arguing that the Commission has sidestepped evidence that they and other parties offered when the Commission concluded that certain suggestions regarding the local transmission planning process were outside the scope of the proceeding.[2128] PIOs argue that while Order No. 1920's reforms take some steps in the right direction, Order No. 1920 does not actually require the kind of comprehensive information transparency, scenario-based planning, multi-benefit analysis, and process coordination necessary for stakeholders to verify whether local transmission projects are prudent or whether a regional solution is more appropriate.[2129] PIOs argue that the Commission must require transmission providers to meet their burden under FPA section 205(e) to prove that their local transmission projects are the least-cost way to meet the needs of the transmission system. PIOs further argue the Commission should grant rehearing to ensure that utilities only construct local transmission projects when they are the best option for maintaining reliability and at least cost to consumers.[2130]

b. Commission Determination

856. We sustain the determination in Order No. 1920 to exclude asset management projects from the information on local transmission planning inputs that transmission providers must include for stakeholder review as part of the Assumptions, Needs, and Solutions Meetings. We reiterate that planning for asset management projects, which do not increase transmission capacity or only do so incidentally, is not required to be included within the scope of local transmission planning that is subject to Order No. 890 transparency requirements,[2131] and as such, it was reasonable for the Commission to exclude them from the requirements in Order No. 1920.[2132] Moreover, the Commission did not propose in the NOPR to require transmission providers

[2112] NESCOE Rehearing Request at 26–31; Ohio Commission Federal Advocate Rehearing Request at 21–24; Old Dominion Rehearing Request at 4, 5–9.

[2113] Old Dominion Rehearing Request at 5, 9.

[2114] *Id.* at 5–6, 8 (contending that Order No. 1920 prohibits different cost allocation methods for economic, reliability, and public policy requirements, which the Commission did not propose in the NOPR).

[2115] *Id.* at 9.

[2116] NESCOE notes that these in-kind replacement projects are known as asset condition projects in New England. NESCOE Rehearing Request at 6.

[2117] *Id.* at 26–33, 34.

[2118] *Id.* at 30–31 (citing *Cal. Pub. Utils. Comm'n* v. *FERC,* 20 F.4th at 800).

[2119] *Id.* at 29.

[2120] *Id.* at 28.

[2121] Ohio Commission Federal Advocate Rehearing Request at 21–22.

[2122] In PJM, ''supplemental projects'' is the term used for local projects. *Id.* at 23.

[2123] *Id.*at 23–24.

[2124] *Id.* at 21, 23.

[2125] Industrial Customers Rehearing Request at 29–31.

[2126] *Id.* at 33–34.

[2127] *Id.* at 38.

[2128] PIOs Rehearing Request at 50.

[2129] *Id.* at 51–52.

[2130] *Id.* at 53–54 (citing *Ky. Mun. Energy Agency* v. *FERC,* 45 F.4th 162, 178 (D.C. Cir. 2022)) (other citations omitted).

[2131] Order No. 1920, 187 FERC ¶ 1625 (citing *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)).

[2132] *Id.* P 1625.

to include information related to asset management projects in the information that they provide as part of the Assumptions, Needs, and Solutions Meetings. Instead, to enhance stakeholders' visibility into local transmission planning inputs as they are integrated into the regional transmission planning process, the Commission proposed in the NOPR—and adopted in the final rule—requirements to enhance the transparency of such inputs, which are already subject to the local transmission planning transparency requirements of Order No. 890, in the regional transmission planning process.[2133] We continue to expect these reforms to enhance the transparency between the local and regional transmission planning processes, which 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.[2134] That said, we note that nothing in Order No. 1920 prevents transmission providers from choosing to apply Order No. 1920's requirements to enhance the transparency of local transmission planning inputs to asset management projects.

857. We disagree with parties that request rehearing on the grounds that the Commission's decision-making was arbitrary and capricious or failed to consider the record evidence. Further, we disagree with Ohio Commission Federal Advocate that the Commission neglected its duty under the FPA to ensure just and reasonable rates. We continue to find, as we found in Order No. 1920, that the enhanced transparency requirements are specifically designed to provide needed transparency to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[2135] As such, we find that the scope of the relevant reforms required by Order No. 1920 is sufficient to remedy the deficiencies in local transmission planning that the Commission set out to resolve in Order No. 1920, even if some parties would have preferred that the Commission had gone further.[2136]

858. For similar reasons, we are unpersuaded by Industrial Customers' and PIOs' requests for additional reforms to transmission planning processes generally. The proposals raised by these parties in their rehearing requests were not included in either the NOPR or Order No. 1920 and, as noted above, we find that the relevant reforms required pursuant to Order No. 1920 are sufficient to remedy the problem that Order No. 1920 set out to solve.[2137] The Commission will continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future.[2138]

3. Stakeholder Meeting Clarifications

a. Request for Rehearing and Clarification

859. SERTP Sponsors request clarification that the standard for evaluating transmission providers' obligation to respond to stakeholder feedback is consistent with Order No. 890 and applies equally to local, regional, and Long-Term Regional Transmission Planning.[2139] Specifically, SERTP Sponsors assert that further clarification is necessary with respect to the Commission's statement that transmission providers are encouraged ''to be as responsive as possible to stakeholder comments and questions'' because this statement could be read to go beyond standards previously established in Order No. 890 and expand transmission providers' obligation to respond beyond what is necessary to support meaningful participation in stakeholder meetings.[2140] Thus, SERTP Sponsors request that the Commission clarify that transmission providers are not obligated to incorporate stakeholder proposals or comments into their transmission plans and that the ultimate transmission planning responsibility is with the transmission provider.[2141]

860. Regarding the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, SERTP Sponsors also request that the Commission clarify that these meetings of different transmission providers do not need to be held as one. SERTP Sponsors explain that their transmission planning region consists of multiple transmission providers over a 12-state footprint, and they contend that the Commission should clarify that this requirement can be satisfied by a single transmission provider holding separate meetings that include its own Assumptions, Needs, and Solutions Meetings.[2142] SERTP Sponsors assert that, in the event that the Commission does not so clarify, the requirements for the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting may become unduly burdensome and inconsistent with Order No. 1920's requirement, which is based on the model used by PJM's transmission owners to hold separate meetings for different local transmission owners' local plans.[2143] SERTP Sponsors argue that holding ''collective'' Assumptions, Needs, and Solutions Meetings is unnecessary to achieve the Commission's transparency objections, and further contends that requiring so would be an unexplained departure from the PJM precedent and otherwise arbitrary and capricious.[2144]

b. Commission Determination

861. We clarify, in response to SERTP Sponsors' request, that transmission providers are not obligated to incorporate stakeholder proposals or comments resulting from the stakeholder meeting process into their transmission plans, and we agree with SERTP Sponsors that the ultimate transmission planning responsibility remains with the transmission provider.[2145] In encouraging transmission providers to be as responsive as possible to stakeholder comments and questions as part of the stakeholder meeting process, the Commission in Order No. 1920 did not establish new requirements for

[2133] NOPR, 179 FERC ¶ 61,028 at P 398 (identifying the need for reform based in part on a finding that ''implementation of [the Order No. 890 local transmission planning principles] in local transmission planning processes appears to remain uneven'', and that ''reforms to better ensure more consistent implementation of these principles may be timely''); *id.* P 400 (proposing to require transmission providers to revise their OATTs ''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.''); *id.* P 402 (stating that ''requirements are needed to ensure just and reasonable Commission-jurisdictional rates because the information provided will better facilitate the identification of regional transmission facilities''); Order No. 1920, 187 FERC ¶ 61,068 at P 1625 (clarifying that the 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'' and does not apply to asset management projects)).

[2134] Order No. 1920, 187 FERC ¶ 61,068 at P 1629.

[2135] *Id.* P 1632.

[2136] *See New York* v. *FERC,* 531 U.S. at 26–27 (affirming that the Commission did not have an obligation extend its open access remedy to bundled retail transmissions because the remedy it ordered constituted a sufficient response to the problems the Commission had identified in the wholesale market).

[2137] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 1648, 1737.

[2138] We note, for example, the ongoing proceeding in Docket No. AD22–8–000 on Transmission Planning and Cost Management.

[2139] SERTP Sponsors Rehearing Request at 23–24.

[2140] *Id.* at 24 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1645) (emphasis omitted).

[2141] *Id.*

[2142] *Id.* at 24–25.

[2143] *Id.* at 25.

[2144] *Id.* at 25 (citations omitted).

[2145] *Id.* at 24.

transmission providers that did not previously apply; rather, the description of the requirement that transmission providers respond to questions or comments in a manner that allows stakeholders to meaningfully participate in the stakeholder meetings explains existing requirements established under Order No. 890 and that apply to local transmission planning processes, existing Order No. 1000 regional transmission planning processes, and Long-Term Regional Transmission Planning processes.[2146]

862. In response to SERTP Sponsors' request that the Commission clarify that the stakeholder meetings of the different transmission providers do not need to be held collectively as a single meeting,[2147] we agree and clarify that, provided that the transmission provider meets the requirements of Order No. 1920 with respect to public notices and opportunities for stakeholders to submit comments before and after each meeting, transmission providers need not hold a single stakeholder meeting among all transmission providers in a transmission planning region. We recognize that transmission planning regions often cover significant geographic range and are comprised of many diffuse transmission providers, such that imposing a requirement that each stakeholder meeting includes all transmission providers and stakeholders may create undue burden and impede meaningful participation. Instead, transmission providers may hold separate Assumptions Meetings, Needs Meetings, and Solutions Meetings for individual transmission providers within a transmission planning region, provided that the process ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning information throughout the regional transmission planning process and otherwise meets all the Order No. 1920 requirements described above.

C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

1. Eligibility

a. Order No. 1920

863. In Order No. 1920, the Commission required transmission providers, as part of each Long-Term Regional Transmission Planning cycle, to 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.[2148] The Commission also required that 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 facilities anticipates replacing in-kind with a new transmission facility during the next 10 years) for use in Long-Term Regional Transmission Planning sufficiently early in each Long-Term Regional Transmission Planning cycle.[2149]

864. The Commission further adopted 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.[2150] The Commission clarified that, for the purposes of the 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; 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.[2151]

865. Similarly, the Commission also clarified that, for the purposes of the right-sizing reform, 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.[2152]

866. In Order No. 1920, the Commission also required transmission providers to establish a multi-step process in their OATTs that provides for the implementation of the right-sizing reform. Specifically, the Commission required that 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.[2153] Next, the Commission required that, 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.[2154] The Commission clarified that it is at this stage that 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).[2155] Finally, the Commission required that, 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, then the right-sized

[2146] *See* Order No. 890, 118 FERC ¶ 61,119 at P 452 (''Transmission providers are, however, required to craft a process that allows for a reasonable and meaningful opportunity to meet or otherwise interact meaningfully.''); *id.* P 454 (''This means that customers 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.''); *id.* P 488 (''The transmission planning required by this Final Rule is intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers.'').

[2147] SERTP Sponsors Rehearing Request at 25.

[2148] Order No. 1920, 187 FERC ¶ 61,068 at P 1677.

[2149] *Id.*

[2150] *Id.* P 1678 & n.3580.

[2151] *Id.* P 1678.

[2152] *Id.* P 1679.

[2153] *Id.* P 1681.

[2154] *Id.*

[2155] *Id.*

replacement transmission facility must be considered for selection.[2156]

867. The Commission further required that, for the purposes of implementing the right-sizing reform, transmission providers must propose on compliance a threshold that does not exceed 200 kV to be used in identifying 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.[2157] The Commission clarified 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.[2158]

b. Requests for Rehearing and Clarification

868. In its rehearing request, Advanced Energy argues that the term ''right-sized replacement facility'' is too vague.[2159] Competition Coalition argues that the definition of the term ignores Order No. 1000–A because the Commission has already determined in Order No. 1000–A that the replacement of an entire transmission facility is an entirely new transmission facility.[2160] Competition Coalition notes that, in Order No. 1000–A, the Commission addressed the issue of granting a preference for an incumbent transmission owner to build a transmission project for upgrades and not an entirely new transmission facility, determining that an upgrade involves the replacement of only part of an existing facility.[2161] Competition Coalition argues that since Order No. 1920 fails to acknowledge the justification for the Commission's departure from existing Commission precedent that limits retention of a preference only for a regional transmission project that represents a replacement of part of an existing transmission facility and not the replacement of an entire transmission facility, Order No. 1920 is arbitrary and capricious.[2162]

869. Similarly, some petitioners argue that Order No. 1920's findings regarding rights-of-way are flawed or inconsistent with Commission precedent.[2163] For example, Advanced Energy highlights that language regarding the ''same general route as, and/or use [ ] the existing rights-of-way of, the existing transmission facility identified as needing to be replaced'' could require anything from zero land acquisition cost (if the facility is entirely within a wholly owned right-of-way) to millions of dollars (if the facility is entirely outside of an existing right-of-way but follows the same general route).[2164] Advanced Energy argues that, given such vagueness, to have the chance of passing muster under the APA, the Commission should remove this ambiguity by limiting any right of first refusal to a right-sized replacement facility that is entirely within existing, permanent rights-of-way.[2165] NESCOE similarly argues that the final rule's lack of a definition of ''general route'' or discussion of why it is appropriate to use a vague term in place of the well-established ''rights-of-way'' necessitates the Commission to act to fulfill its statutory duty under the FPA and that, as written, the right-sizing reform could be interpreted to the detriment of consumers.[2166]

870. Competition Coalition argues that the Commission's right-sizing reform contravenes existing Commission precedent regarding the use of rights-of-way, noting that, under Order No. 1000–A, the Commission found that the use of an existing right-of-way is not determinative of whether the facility is a new transmission facility but rather the relevant issue was ''whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities.'' [2167] Competition Coalition further points to Commission rejection of a proposal from MISO to give preference to transmission owners for facilities built on the existing rights-of-way since the Commission determined that issues surrounding rights-of-way is an issue for the authority granting the rights-of-way.[2168]

871. Competition Coalition argues that the OATT language associated with the right-sizing reform is ambiguous, unworkable, and will cause confusion and litigation.[2169] Competition Coalition highlights the terms ''anticipates,'' ''right-sizing,'' ''as discussed in Order No. 1920,'' ''not to exceed 200 kV,'' ''more efficiently,'' and ''cost-effectively'' as being undefined in the final rule.[2170] Competition Coalition also contends that the absence of OATT language that gives an independent entity the responsibility to carry out and administer right-sizing opportunities or monitor against potential planning abuses confirms the need for an independent transmission system planner or monitor.[2171]

872. In its rehearing request, Dominion requests clarification of the proposed 200 kV threshold for determining whether a transmission facility is eligible for right-sizing.[2172] Specifically, Dominion explains that while the Commission refers to a ''maximum threshold,'' Dominion seeks clarification that the use of the word ''maximum'' does not foreclose evaluation of projects above and below that threshold. Dominion explains that, in simpler terms, transmission providers must consider for right-sizing purposes all transmission facilities with projected in-kind replacements currently operating at or above 200 kV, but they may propose a lower threshold on compliance.[2173]

c. Commission Determination

873. We sustain our findings in response to Advanced Energy's, Competition Coalition's, and NESCOE's rehearing requests pertaining to the term ''right-sized replacement facility.'' As the Commission explained in Order No. 1920, the right-sizing reform was adopted, as modified from the NOPR proposal, with additional requirements to ensure that the use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.[2174] As

[2156] *Id.* As explained in the Right of First Refusal section below, the Commission required the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs. *Id.* P 1702.

[2157] *Id.* PP 1677, 1683 & n.3584.

[2158] *Id.* at P 1685.

[2159] Advanced Energy Rehearing Request at 14–15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678).

[2160] Competition Coalition Rehearing Request at 51–57 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 426; *NYISO,* 151 FERC ¶ 61,040 at P 96 (additional citation omitted)).

[2161] Competition Coalition at 51–52 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 426).

[2162] *Id.* at 52.

[2163] Advanced Energy Rehearing Request at 14–15 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678); Competition Coalition Rehearing Request at 57–59 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678; *MISO,* 147 FERC ¶ 61,127 at P 244; *NYISO,* 151 FERC ¶ 61,040 at P 96).

[2164] Advanced Energy Rehearing Request at 14 (citing Order No. 1920, 187 FERC ¶ 61,068 at P 1678).

[2165] *Id.* at 14–15.

[2166] NESCOE Rehearing Request at 32–33.

[2167] Competition Coalition Rehearing Request at 57–58 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 427).

[2168] *Id.* (citing *MISO,* 147 FERC ¶ 61,127 at P 244).

[2169] *Id.* at 72.

[2170] *Id.* at 73–74.

[2171] *Id.* at 74.

[2172] Dominion Rehearing Request at 35.

[2173] *Id.* at 35–36.

[2174] *Id.* P 1679.

highlighted in Order No. 1920, a right-sized replacement transmission facility would replace the existing transmission facility that the transmission provider included in its in-kind replacement estimate, and extends to any portion of the right-sized replacement facility located within a given transmission provider's retail distribution service territory or footprint.[2175] The Commission found 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.[2176]

874. In response to Competition Coalition's argument that Order No. 1920 is inconsistent with Order No. 1000–A, which specified that upgrades do not include entirely new transmission facilities, we note that the Commission is entitled to change its approach and depart from prior precedent, provided that it acknowledges the change in policy and provides a reasoned explanation for the new approach.[2177] We acknowledge that in Order No. 1920, the Commission, with explanation, departed from its precedent in Order No. 1000–A, as well as in *MISO* and *NYISO.*[2178] In Order No. 1920, the Commission explicitly recognized 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.'' [2179] However, the Commission found 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.[2180] The Commission then explained at length why this is the case, satisfying the Commission's obligation to provide a reasoned explanation for its new policy.

875. Specifically, the Commission found that 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 at the regional level; instead, it will *promote* the consideration of potential regional transmission solutions to address Long-Term Transmission Needs.[2181] When compared against the alternative of piecemeal development of in-kind replacement facilities, the right-sizing reform ensures that Long-Term Regional Transmission Planning considers a broader set of needs, including needs related to replacement of aging transmission infrastructure.[2182] The Commission further stated that, absent a federal right of first refusal for right-sized replacement transmission facilities, 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 because it 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.[2183] Thus, the federal right of first refusal for right-sized replacement transmission facilities will remove a barrier to development of more efficient or cost-effective regional solutions that could encompass both replacements of aging transmission infrastructure and regional transmission solutions to address Long-Term Transmission Needs. Similarly, the Commission found that requiring the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs 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.[2184]

876. The Commission found that, given 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 a federal right of first refusal for right-sized replacement transmission facilities is necessary to effectuate the right-sizing reform and ensure that Commission jurisdictional rates are just and reasonable.[2185] We sustain this finding, and we continue to conclude that a federal right of first refusal for right-sized replacement transmission facilities 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 the Commission-jurisdictional rates that customers pay are just and reasonable.[2186] As such, we find that the Commission has provided a reasoned explanation for its decision to depart from prior precedent and require a federal right of first refusal for right-sized replacement transmission facilities.

877. We are unpersuaded by Advanced Energy's, Competition Coalition's, and NESCOE's claims regarding the use of the term ''rights-of-way'' in defining a right-sized replacement transmission facility. As in Order No. 1000, we find that the retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way,[2187] and nothing in the definition of ''in-kind replacement transmission facility'' or ''right-sized replacement transmission facility'' would affect the retention, modification, or transfer of rights-of-way. While we recognize Advanced Energy's argument that a right-sized replacement transmission facility may require additional land for a right-of-way, we decline to speculate on land acquisition costs because land acquisition costs vary from transmission

[2175] *Id.* P 1702.

[2176] *Id.* P 1682.

[2177] *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515–516; *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 784 (1968); *see also State Farm,* 463 U.S. at 42 (''[W]e fully recognize that regulatory agencies do not establish rules of conduct to last forever.'') (internal quotations omitted); *Greater Bos. Television Corp.* v. *FCC,* 444 F.2d 841, 852 (D.C. Cir. 1970) (an agency may change its course as long as it ''suppl[ies] a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored.''), *cert. denied,* 403 U.S. 923 (1971).

[2178] *See MISO,* 147 FERC ¶ 61,127 at P 238; *NYISO,* 151 FERC ¶ 61,040 at P 96. In Order No. 1000–A, 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.

[2179] Order No. 1920, 187 FERC ¶ 61,068 at P 1704.

[2180] *Id.* P 1706; *see also* Order No. 1920, 187 FERC ¶ 61,068 at P 1705 (explaining that Order No. 1000 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 and created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions at the regional level) (citations omitted).

[2181] *Id.* P 1706.

[2182] *Id.*

[2183] *Id.*

[2184] *Id.* P 1703.

[2185] *Id.* P 1706.

[2186] *See id.* P 1703.

[2187] *Id.* P 319.

facility to transmission facility. In any case, the fact that there may be additional land acquisition costs does not, as Advanced Energy argues, render the definition of a right-sized replacement transmission facility vague. We note, however, that transmission providers could consider the potential for such costs when they are evaluating whether a particular right-sized replacement transmission facility is a more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs.

878. Moreover, we disagree that Order No. 1920's inclusion of the term ''general route'' in the definition of ''in-kind replacement transmission facility'' and ''right-sized replacement transmission facility'' renders those definitions vague. Rather, we find the term ''general route,'' when read in the context of Order No. 1920's example detailing which transmission facilities would be eligible for right-sizing,[2188] makes clear that the right-sizing reform considers existing topology of the transmission system to ensure that the right-sizing reform applies to *replacement* transmission facilities only.[2189] We find that it is important to include this term to provide a reasonable bound of the definition of both in-kind replacement transmission facilities and right-sized replacement transmission facilities. Further, a right-sized replacement transmission facility may require changes to or expansions of rights-of-way to accommodate that right-sized replacement transmission facility, and it is not feasible to list every type or circumstance that may bear upon existing rights-of-way. Accordingly, we find that the requirement for a right-sized replacement transmission facility to also be located in the same general route as the existing transmission facility identified for replacement provides a reasonable limitation on the location of such a right-sized replacement transmission facility. For example, if a transmission provider anticipates replacing an existing transmission facility because it has reached the end of its useful life and the replacement transmission facility (either in-kind or right-sized) requires modifications to that facility's rights-of-way to accommodate other infrastructure projects or avoid environmentally sensitive areas, those modifications to existing rights-of-way are permitted under the term ''same general route.'' We note that Order No. 1920's example relied on interconnection points to describe which in-kind replacement transmission facilities would be eligible for right-sizing,[2190] specifically, that a right-sized replacement transmission facility that connects the same interconnection points to which an in-kind replacement transmission facility connects qualifies under the term ''same general route.'' We reiterate that these limitations are appropriate to ensure that the right-sizing reform applies to *replacement* transmission facilities only. For example, a new transmission facility would not qualify as a right-sized replacement transmission facility if it has significantly different interconnection points than the in-kind replacement facility.

879. Furthermore, we find Competition Coalition's contention that the definition of ''right-sized replacement transmission facility'' is inconsistent with Order No. 1000 regarding the use of rights-of-way to be inapposite. In Order No. 1000, the Commission stated 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.'' [2191] The Commission stated that ''[t]he issue is not whether the upgrade would be located in an existing right-of-way, but whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities.'' [2192] In other words, the Commission found in Order No. 1000 that whether a regional transmission facility does or does not require the expansion of an existing right-of-way is not relevant to whether that facility is an upgrade. In contrast, for the reasons discussed directly above, in Order No. 1920 the Commission found it necessary that, to qualify as a right-sized replacement transmission facility, a transmission facility must be located in the same general route as, and/or use or expand the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate.

880. We are unpersuaded by Competition Coalition's arguments regarding specific terminology in the right-sizing reform. However, we provide additional context for certain terms and phrases included in the right-sizing reform. We sustain the definition of ''right-sizing'' to mean ''the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.'' [2193] The Commission noted that 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).[2194] Regarding the other terms highlighted by Competition Coalition, we find that, read in the context of the right-sizing reform, as well as Order No. 1920, these terms are clear, and we disagree with Competition Coalition that the absence of independent transmission monitor language confirms the need for such an entity in the context of right-sizing.[2195]

881. We grant clarification to Dominion's requests regarding the 200 kV threshold for determining whether a transmission facility is eligible for right-sizing. We clarify that the Commission's finding in Order No. 1920 that the kV threshold must not exceed 200 kV means that transmission providers must include in their in-kind replacement estimates all transmission facilities operating at or above 200 kV that they anticipate replacing in-kind during the next 10 years. We also clarify that transmission providers may establish a threshold *lower* than 200 kV to ensure that a larger number of transmission facilities may be included. Put simply, transmission providers may propose a threshold for all transmission facilities that are eligible to be right-sized, so long as that threshold is under 200 kV.

2. Right of First Refusal for Right-Sized Replacement Transmission Facilities Selected To Meet Long-Term Transmission Needs

a. Order No. 1920

882. In Order No. 1920, the Commission required the establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs.[2196] In adopting a federal right of first refusal requirement for a right-sized replacement transmission facility, the Commission noted that a federal right of first refusal is an exception to Order No. 1000's general requirement for transmission providers to eliminate any

[2188] *Id.* P 1680.

[2189] *Id.* PP 1678, 1679.

[2190] *Id.* P 1680.

[2191] Order 1000–A, 139 FERC ¶ 61,132 at P 427.

[2192] *Id.*

[2193] Order No. 1920, 187 FERC ¶ 61,068 at P 1678.

[2194] *Id.* P 1678 n.3580.

[2195] The Commission will continue to consider potential additional local transmission planning reforms, such as independent transmission monitors, along with other transmission reforms in the future. *See supra* Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

[2196] Order No. 1920, 187 FERC ¶ 61,068 at P 1702; *see also supra* Analysis under Section 206 section.

federal right of first refusal for regional transmission facilities selected in a regional transmission plan.[2197] The Commission explained that 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, the Commission found that it will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. Further, the Commission explained that, when compared against the alternative of piecemeal development of in-kind replacement transmission facilities, 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).[2198]

883. Additionally, the Commission explained that, in requiring a federal right of first refusal for a right-sized replacement transmission facility, Order No. 1000 did not alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to their own transmission facilities, regardless of whether the upgrade is selected.[2199]

b. Requests for Rehearing and Clarification

884. Certain parties request rehearing of Order No. 1920's establishment of a federal right of first refusal for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs, on the grounds that the Commission deviated from prior precedent without reasoned explanation and, therefore, such requirements are arbitrary and capricious.[2200] For example, Advanced Energy states that the Commission failed to explain how providing for a right of first refusal for right-sized replacement transmission facilities in Order No. 1920 was consistent with prior Commission findings that granting an incumbent utility a federal right of first refusal can lead to rates that are unjust and unreasonable.[2201]

885. Advanced Energy further argues that the Commission's provision of a federal right of first refusal for right-sized replacement transmission facilities is inconsistent with the general federal policy against anticompetitive practices.[2202]

886. Relatedly, Advanced Energy, Competition Coalition, and PIOs argue that the inclusion of a federal right of first refusal as part of the right-sizing reform will create incentives for incumbent transmission owners to use the local transmission planning processes to undermine the regional transmission planning process, resulting in less efficient or cost-effective solutions and, therefore, unjust and unreasonable rates.[2203] For instance, Competition Coalition argues that a profit-motivated incumbent transmission owner will have incentives to add even more in-kind replacements into its local transmission plan because of the possibility that the transmission planning region will then right-size those projects into an even larger facility in which the incumbent utility would be allowed to invest without any competition, thus preserving, reinforcing, and expanding its monopoly position.[2204]

c. Commission Determination

887. We are unpersuaded by rehearing requests arguing that Order No. 1920's establishment of a federal right of first refusal for right-sized replacement transmission facilities selected to meet Long-Term Transmission Needs is arbitrary and capricious. In Order No. 1000, the Commission required transmission providers to eliminate federal rights of first refusal because those federal rights of first refusal allowed transmission providers to undermine 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.[2205] Moreover, in Order No. 1000 the Commission found that federal rights of first refusal created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions at the regional level.[2206]

888. In Order No. 1920, the Commission found that 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 to 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.[2207] The Commission further explained that, compared to the alternative of piecemeal development of in-kind replacement transmission facilities, a federal right of first refusal for right-sized transmission facilities is appropriate because right-sized replacement transmission facilities represent the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs (otherwise, they would not be selected).[2208]

889. We recognize that requiring the federal right of first refusal for right-sized replacement transmission facilities is a departure from the Order No. 1000's requirement that transmission providers eliminate federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation. However, we find the departure, in this instance, to be necessary in order to shift the balance of transmission facility construction and remove a barrier to the selection of more efficient or cost-effective regional transmission facilities. As the Commission found, the existing piecemeal approach to upgrading the transmission system results in inefficiencies and increased rates for consumers.[2209] The Commission is improving the efficiency of the transmission planning process and ensuring rates are just and reasonable by promoting the consideration of right-sized replacement transmission facilities, subject to evaluation and selection processes in Long-Term Regional Transmission Planning, and by establishing the availability of the federal right of first refusal for such right-sized replacement transmission facilities.[2210]

[2197] *Id.* P 1704 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 313).

[2198] *Id.* P 1706.

[2199] *Id.* P 1705 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 319 (internal citation omitted)).

[2200] Advanced Energy Rehearing Request at 15–16; Competition Coalition Rehearing Request at 40–43; Designated Retail Regulators Rehearing Request at 41–42; Industrial Customers Rehearing Request at 9.

[2201] Advanced Energy Rehearing Request at 16 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 360; *FCC* v. *Fox Television Stations,* 556 U.S. at 515).

[2202] *Id.* at 10–11; *see also* Competition Coalition Rehearing Request at 67–68.

[2203] Advanced Energy Rehearing Request at 13–14; Competition Coalition Rehearing Request at 69–71; PIOs Rehearing Request at 51–54.

[2204] Competition Coalition Rehearing Request at 69–70.

[2205] Order No. 1000, 136 FERC ¶ 61,051 at PP 253, 256, 313.

[2206] *Id.* P 257.

[2207] Order No. 1920, 187 FERC ¶ 61,068 at P 1682.

[2208] *Id.* P 1706.

[2209] *Id.* PP 1574, 1706.

[2210] Although we find that the Commission has supported the inclusion of the right-sizing reforms

Continued

890. We sustain Order No. 1920's finding that the right-sizing reform will promote the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. Specifically, the federal right of first refusal will provide transmission providers with 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, and this, in turn, will encourage transmission providers to provide their best in-kind replacement estimates.[2211] Accordingly, we continue to 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 identified and selected, and therefore that Commission-jurisdictional rates are just and reasonable.

891. In Order No. 1920, the Commission explained that, in the context of the right-sizing reform, a federal right of first refusal will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs because, absent the right-sizing reform, those needs would be addressed in a piecemeal manner.[2212] This will in turn benefit consumers by helping to ensure that the rates that they pay are just and reasonable. Furthermore, we believe that providing a federal right of first refusal for selected right-sized replacement transmission facilities is consistent with Order No. 1920's finding that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements 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.[2213] As such, as discussed in the Eligibility section above, we find that it is appropriate to alter the Commission's policy regarding the removal of the federal right of first refusal by providing a federal right of first refusal for selected right-sized replacement transmission facilities. This is particularly true because the reforms that we require here serve a similar purpose as removing the federal right of first refusal for regional transmission facilities selected in the regional transmission plan for purposes of cost allocation in Order No. 1000. In each instance, the Commission's goal was to ensure that the more efficient or cost-effective regional transmission facilities are considered, thereby ensuring that Commission-jurisdictional rates are just and reasonable—in Order No. 1000, that was accomplished by removing the federal right of first refusal for selected regional transmission facilities in certain instances, while in Order No. 1920, it was by establishing a federal right of first refusal in the limited instances where it incentivizes transmission providers to consider right-sized replacement transmission facilities as more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs. The reforms related to the federal right of first refusal in Order Nos. 1000 and 1920 each seek to ensure that more efficient or cost-effective regional transmission facilities are considered thereby resulting in just and reasonable rates. Protecting consumers and ensuring Commission-jurisdictional rates are just and reasonable are fundamental requirements of the Federal Power Act and we believe that the reforms in Order No. 1920 accomplish these mandates.

892. We also note that this federal right of first refusal applies only to selected right-sized replacement transmission facilities, which, absent the right-sizing reform, would likely not otherwise be identified for potential selection in either the existing Order No. 1000 regional transmission planning process or the Long-Term Regional Transmission Planning process. That is because there is currently no requirement for transmission providers to submit their in-kind replacement transmission facilities to the regional transmission planning process for potential right-sizing. In addition, as the Commission explained in Order No. 1920, 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, and we continue to find that, absent a federal right of first refusal, 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.[2214] This is because, absent the federal right of first refusal, the incumbent transmission provider would not be assured that it would have the opportunity to invest in the right-sized replacement transmission facility and therefore very likely would chose to build the less efficient or cost-effective in-kind replacement transmission facility. Therefore, the right-sizing reform's federal right of first refusal provides the needed incentives to ensure that in-kind replacement transmission facilities are considered in the Long-Term Regional Transmission Planning process and selected when they are more efficient or cost-effective transmission solutions while also not substantially reducing the number of transmission facilities that would otherwise be subject to a competitive transmission development process.

893. We are also unpersuaded by Advanced Energy's arguments that the federal right of first refusal associated with the right-sizing reform is inconsistent with federal policies against anticompetitive practices. As we note above, given the existing federal rights of first refusal that transmission owners have and that we are not altering here, it is unlikely that right-sized replacement transmission facilities would ever be considered in competitive transmission development processes. Therefore, we do not believe that the right-sizing reform will significantly decrease competition compared to the status quo.

894. We are unpersuaded by rehearing requests that argue that the federal right of first refusal associated with the right-sizing reform will create incentives for incumbent transmission providers to use local transmission planning processes to undermine regional transmission planning processes. Under Order No. 1920's right-sizing reforms, incumbent transmission owners will have an incentive to identify in-kind replacement transmission facilities that could be right-sized to retain a federal right of first refusal over regional transmission facilities, but that incentive does not undermine the regional transmission planning process. Instead, it will enhance regional transmission planning by expanding the range of potential regional transmission solutions to Long-Term Transmission Needs considered through Long-Term Regional Transmission Planning, facilitating the identification and

as a component of a just and reasonable replacement rate, we consider these reforms as an enhancement to, rather than essential to, the Long-Term Regional Transmission Planning process. Absent the right-sizing reforms, the Commission would have established the other Long-Term Regional Transmission Planning requirements as a sufficient just and reasonable replacement rate.

[2211] Order No. 1920, 187 FERC ¶ 61,068 at P 1703.

[2212] *Id.* P 1706.

[2213] *Id.* P 85.

[2214] *Id.* P 1706.

selection of more efficient or cost-effective regional transmission facilities and helping to ensure just and reasonable Commission-jurisdictional rates. Moreover, because Order No. 1920 requires that a right-sized replacement transmission facility 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,[2215] a right-sized replacement transmission facility will be selected only where it is the more efficient or cost-effective transmission solution. As such, there is no guarantee that an in-kind replacement transmission facility that a transmission provider identifies in its in-kind replacement estimates list will be right-sized and selected. To the extent that the evaluation of a transmission provider's in-kind replacement transmission facility determines that the in-kind replacement transmission facility cannot be right-sized to more efficiently or cost-effectively address Long-Term Transmission Needs, then it will not be selected as a right-sized replacement transmission facility.

3. Confidentiality of In-Kind Replacement Estimates

a. Order No. 1920

895. In Order No. 1920, the Commission explained that to the extent 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, the Commission added that, once 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, the transmission providers must make public the underlying in-kind replacement transmission facility.[2216]

b. Requests for Rehearing and Clarification

896. In their rehearing requests, Dominion and Indicated PJM TOs argue that the Commission's decision on confidentiality for in-kind replacement estimate lists fails to adequately address concerns regarding the possible harm caused by release of the in-kind replacement estimate lists.[2217] Both Dominion and Indicated PJM TOs argue that considering the Commission's determination that once a replacement transmission facility can be right-sized, that information will be made publicly available to stakeholders, there is limited value in providing the in-kind replacement estimate list to others.[2218]

897. Further, Indicated PJM TOs argue that confidentiality agreements or provisions do not provide adequate protection against the damage of disclosure of in-kind replacement estimate lists since non-disclosure agreements do not impose any specific safeguards on the information disclosed.[2219] Indicated PJM TOs note that the Commission's general Non-Disclosure Agreement for CEII provides that violations of that agreement ''may result in criminal or civil sanctions'' against the recipient, and the Commission's Model Protective Order provides that ''[a]ny violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.''[2220] Indicated PJM TOs argue that the requirement that a transmission owner make public 10-years' worth of replacement information before transmission plans are made public as part of the Long-Term Regional Transmission Planning process gives competing developers a competitive advantage that is inconsistent with the FPA's prohibition on undue discrimination and preferences.[2221]

c. Commission Determination

898. In response to Dominion's and Indicated PJM TOs' arguments regarding the possible harm caused by release of the in-kind replacement estimate lists, we continue to find that existing rules governing confidential or commercially sensitive information provide for the safekeeping of that information. We note that Order No. 890 required transmission providers, in consultation with affected parties, to develop mechanisms like confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.[2222] To the extent that transmission providers believe that existing provisions are inadequate, they may submit an FPA section 205 filing with additional protections, and the Commission will evaluate them to ensure they are just and reasonable and otherwise comply with the applicable requirements. Moreover, in determining that disclosure of in-kind replacement estimate lists may occur subject to confidentiality provisions, the Commission balanced concerns about disclosure against the importance of transparency and meaningful stakeholder participation in regional transmission planning and cost allocation processes, as required under Order Nos. 890 and 1000. We continue to find, consistent with prior precedent, that disclosure subject to appropriate mechanisms for confidentiality strikes an appropriate balance between these interests.[2223]

XII. Interregional Transmission Coordination

A. Order No. 1920

899. In Order No. 1920, the Commission required 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 Order No. 1920. More specifically, the Commission required 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.[2224] Additionally, the Commission required transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional

[2215] *Id.* P 1681.

[2216] Order No. 1920, 187 FERC ¶ 61,068 at P 1736.

[2217] Dominion Rehearing Request at 36–37; Indicated PJM TOs Rehearing Request at 6–7.

[2218] Dominion Rehearing Request at 36–37; Indicated PJM TOs Rehearing Request at 7–8.

[2219] Indicated PJM TOs Rehearing Request at 8–9.

[2220] *Id.* at 9 (citing FERC, CEII General Non-Disclosure Agreement (Apr. 19, 2020), *https://www.ferc.gov/media/1928;* FERC, Model Protective Order (May 11, 2020), available at *https://www.ferc.gov/administrative-litigation-0*).

[2221] *Id.* at 10.

[2222] Order No. 890, 118 FERC ¶ 61,119 at P 460.

[2223] *Tri-State Generation & Transmission Ass'n,* 170 FERC ¶ 61,222, at P 27 (2020); *see also Astoria Generating Co.* v. *N.Y. Indep. Sys. Operator, Inc.,* 136 FERC ¶ 61,155, at PP 21–25 (2011) (adopting protective order and directing respondent to file confidential information and simultaneously release the information to parties who signed non-disclosure certificate); *Pac. Gas Transmission Co.,* 44 FERC ¶ 61,209, at 61,766–67 (1988) (remanding matter to administrative law judge with direction to balance potential harm of disclosing confidential business information sought during discovery against the requesting parties' need for the information).

[2224] Order No. 1920, 187 FERC ¶ 61,068 at P 1751.

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.[2225]

900. The Commission also required transmission providers in each transmission planning region to provide certain additional information concerning Long-Term Regional Transmission Planning on their public websites or through the email list used for communication of information related to interregional transmission coordination procedures.[2226]

B. Comments

901. In its comments, Grid United argues that Order No. 1920 does not solve the challenges of developing transmission, including interregional transmission, and requests that the Commission open a new proceeding focused on interregional transmission and its challenges.[2227]

C. Commission Determination

902. Although we acknowledge Grid United's request that the Commission continue to build upon the progress in Order No. 1920 for regional transmission planning by addressing interregional transmission, we decline to open a new docket at this time, as requested by Grid United.[2228] We find that Order No. 1920 adequately addressed the interregional transmission coordination reforms needed to account for the rule's Long-Term Regional Transmission Planning reforms.[2229] In particular, we continue to find that the reforms in Order No. 1920, taken together, 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, and that there is an opportunity for 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, helping to ensure just and reasonable Commission-jurisdictional rates.[2230] Furthermore, as the Commission found in Order No. 1920, and we reiterate here, 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 including the transmission planning and cost allocation related to such a requirement.[2231] To the extent that the Commission determines that further investigation of this issue is warranted, it can open a new docket at an appropriate time or consider such issues in pending proceedings,[2232] as appropriate.

XIII. Compliance Procedures

A. Order No. 1920

903. In Order No. 1920, the Commission required each transmission provider to submit a compliance filing 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 Order No. 1920, except those adopted in the Interregional Transmission Coordination section above, within 10 months of the effective date of Order No. 1920. The Commission explained that a 10-month compliance period allows transmission providers to fully develop proposals to comply with Order No. 1920 and allows stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. Additionally, the Commission required transmission providers in each transmission planning region to propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle.[2233] The Commission noted, however, that 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.[2234]

904. The Commission further required each transmission provider to submit a compliance filing 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 within 12 months of the effective date of Order No. 1920. The Commission explained that a longer compliance timeframe will allow transmission providers to coordinate with the transmission providers in each of their neighboring transmission planning regions to develop interregional transmission coordination proposals.[2235]

905. Additionally, the Commission required transmission providers that are not public utilities to adopt the requirements of Order No. 1920 as a condition of maintaining the status of their safe harbor tariffs or otherwise satisfying the reciprocity requirement of Order No. 888.[2236]

906. Finally, in Order No. 1920, the Commission explained that it made no changes to the standards used to judge requested variations, as described in Order Nos. 888, 2000, 890, and 1000 and, accordingly, declined a request to apply the independent entity variation standard, rather than the ''consistent with or superior to'' standard, for proposed deviations from the requirements of Order No. 1920.[2237] The Commission stated that, consistent with findings in Order No. 890, the Commission will continue to apply the ''consistent with or superior to'' standard in the context of transmission planning.[2238] The Commission explained that, to the extent that a transmission provider believes that it already complies with any of the requirements in Order No. 1920, it should describe in its compliance filing how the relevant requirements are satisfied, including by referencing

[2225] *Id.* P 1752.

[2226] Order No. 1920, 187 FERC ¶ 61,068 at P 1753.

[2227] Grid United June 12, 2024 Comments at 1–2.

[2228] As noted above, the pleading filed by Grid United is deficient under 18 CFR 385.712(c)(2). Nevertheless, we address Grid United's arguments to provide clarity. *See infra* Introduction and Background section.

[2229] Order No. 1920, 187 FERC ¶ 61,068 at PP 1740–1758.

[2230] *Id.* P 1754.

[2231] *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).

[2232] *See* Order No. 1920, 187 FERC ¶ 61,068 at P 1758 (''[W]e 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.'').

[2233] Order No. 1920, 187 FERC ¶ 61,068 at P 1768. The Commission noted that Order No. 1920 required 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 Order No. 1920 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). *Id.*

[2234] *Id.* P 1768.

[2235] *Id.* P 1770.

[2236] *Id.* P 1771 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63).

[2237] *Id.* P 1772 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769–70; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 1000, 136 FERC ¶ 61,051 at P 815).

[2238] *Id.* P 1772 (citing Order No. 890, 118 FERC ¶ 61,119 at P 160).

specific tariff sheets already on file with the Commission.[2239]

B. Requests for Rehearing and Clarification

907. Dominion and NARUC request rehearing of Order No. 1920's compliance timeframes.[2240] Dominion argues that the Commission failed to consider that many of the same personnel responsible for implementing Order No. 2023 are also responsible for managing the implementation of Order No. 1920's requirements.[2241] NARUC asserts that Order No. 1920's 10-month compliance deadline is insufficient to allow state entities to meaningfully engage on developing cost allocation proposals given existing state retail regulatory duties, the steep learning curve on issues related to Order No. 1920, and internal legal and procedural issues they will need to sort through. NARUC suggests that the record justifies a 14-month compliance period.[2242]

908. Dairyland and PJM request rehearing of Order No. 1920's requirement that transmission providers demonstrate proposed deviations from the requirements of Order No. 1920 are ''consistent with or superior to'' the requirements of Order No. 1920.[2243] Both Dairyland and PJM request that the Commission adopt an independent entity variation standard for compliance with the final rule. Dairyland argues that the Commission failed to consider information and arguments submitted in support of the independent entity variation[2244] and made no attempt to explain why the precedent of Order No. 2003, which identified bases for a different compliance standard for independent entities, is distinguishable or should not be used here.[2245] Along similar lines, PJM argues that aspects of Order No. 1920 are arbitrary and capricious because: (1) the final rule is internally inconsistent given the Commission's recognition of the need for regional flexibility while also including ''numerous prescriptive requirements'' and rejecting requests to apply an ''independent entity variation'' standard of review and instead applying the ''consistent with or superior to'' standard for proposed deviations from the final rule;[2246] and (2) the Commission failed to consider the evidence offered by ISO/RTOs that they need flexibility to implement Long-Term Regional Transmission Planning.[2247]

909. APPA and TAPS request clarification of Order No. 1920's requirements for consultation with stakeholders.[2248] APPA requests that the Commission clarify that transmission providers have an obligation to consult with stakeholders—including public power entities and load-serving entities—in developing compliance filings.[2249] TAPS requests the Commission to clarify that Order No. 1000's general obligation to consult with stakeholders in developing the associated transmission provider's compliance filing applies to all aspects of Order No. 1920 compliance filings, including the evaluation process, selection criteria, and the calculation of benefits.[2250]

910. In its rehearing request, Large Public Power argues that the Commission should clarify that non-public utilities can satisfy the reciprocity requirement of Order No. 888 through one of three means: (1) providing service to a public utility transmission provider under a safe harbor tariff; (2) providing service under a bilateral agreement; or (3) seeking waiver.[2251]

911. SPP requests clarification from the Commission that SPP can deviate from the specific requirements of Order No. 1920 and propose its own Consolidated Planning Process. SPP requests that the Commission clarify that a transmission provider may propose on compliance a new transmission planning process and cost allocation method that deviates from the requirements of Order No. 1920, and that the Commission could issue an order approving such a cost allocation process as consistent with or superior to the requirements of Order No. 1920.[2252]

912. WIRES states that the Commission should grant clarification or, in the alternative, rehearing, that transmission providers are not required to implement the proposed tariff revisions submitted in compliance with Order No. 1920 until the Commission issues ''a final order on compliance.''[2253] WIRES states that Order No. 1920 could be read to create a scenario where transmission providers would be required to begin implementing their OATT provisions submitted in compliance with the requirements of Order No. 1920 *before* receiving a Commission order on compliance accepting such revised Tariff provisions. WIRES argues that this would put transmission providers in the untenable position of expending a significant amount of time and resources in implementing Long-Term Regional Transmission Planning cycles that the Commission could find in a later order are not compliant with Order No. 1920.[2254]

913. Versant Power requests that the Commission clarify, or in the alternative grant rehearing, regarding: (1) what is generally required for a transmission provider to receive a waiver of Order No. 1920's requirements; and (2) whether and how waivers of previous, relevant orders affect Order No. 1920's requirements for transmission providers with those waivers.[2255]

C. Commission Determination

914. We sustain Order No. 1920's requirement that each transmission provider submit a compliance filing within 10 months of the effective date of Order No. 1920 revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in Order No. 1920, except those requirements adopted in the Interregional Transmission Coordination section above. As we noted in Order No. 1920, we continue to find that a 10-month compliance period will allow transmission providers adequate time to fully develop proposals to comply with Order No. 1920.[2256] We also sustain Order No. 1920's requirement that each transmission provider submit a separate compliance filing within 12 months of the effective date of Order No. 1920 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 Order No. 1920.[2257] Nevertheless, as noted above

[2239] *Id.* P 1773.

[2240] Dominion Rehearing Request at 37–39; NARUC Rehearing Request at 18–21.

[2241] Dominion Rehearing Request at 38 (citing *State Farm,* 463 U.S. at 43).

[2242] NARUC Rehearing Request at 20–21.

[2243] Dairyland Rehearing Request at 3–7; PJM Rehearing Request at 10–14.

[2244] Dairyland Rehearing Request at 4.

[2245] *Id.* at 3–4, 6–7; *see also* PJM Rehearing Request at 13 n.60.

[2246] PJM Rehearing Request at 10–11, 41; *see also* Dairyland Rehearing Request at 7.

[2247] PJM Rehearing Request at 11–14, 42.

[2248] APPA Rehearing Request at 6–7; TAPS Rehearing Request at 14–19.

[2249] APPA Rehearing Request at 7.

[2250] TAPS Rehearing Request at 18–19.

[2251] Large Public Power Rehearing Request at 23–24.

[2252] SPP Rehearing Request at 2–4.

[2253] WIRES Rehearing Request at 5–6, 16–18.

[2254] WIRES Rehearing Request at 16–18.

[2255] Versant Power Rehearing Request at 9–16. Versant Power notes that its request for clarification may be withdrawn because of a separate waiver filing. *Id.* at 1 n.4. Versant Power withdrew its rehearing request on September 10, 2024.

[2256] Order No. 1920, 187 FERC ¶ 61,068 at P 1768.

[2257] *Id.* P 1770.

in the Duration of the Engagement Period section above, if we grant an extension of the required Engagement Period when Relevant State Entities make a showing that they require additional time to finalize cost allocation discussions, we will also, as appropriate, extend, *sua sponte,* the relevant Order No. 1920 compliance deadlines to ensure that any extension of the Engagement Period would not conflict with the required compliance deadlines.

915. We clarify that the effective date associated with this order on rehearing and clarification does not extend the relevant compliance deadlines associated with Order No. 1920. In calculating the required dates for compliance filings (*e.g.,* 10 months for revisions to a transmission provider's OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in Order No. 1920, and 12 months for revisions to a transmission provider's 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 Order No. 1920), transmission providers should use the effective date of Order No. 1920 (*i.e.,* August 12, 2024) and not the effective date for the changes to Order No. 1920 made in this order on rehearing and clarification.

916. We are unpersuaded by Dominion's and NARUC's arguments that the Commission should require a longer compliance period. We note that in Order No. 1920 the Commission modified the NOPR proposal for an eight-month compliance period to allow an additional two months.[2258] While we appreciate Dominion's concerns regarding personnel responsible for implementing both Order Nos. 1920 and 2023, we believe that we have provided sufficient time for transmission providers to develop compliance filings.

917. We also sustain Order No. 1920's requirement that, consistent with the Commission's findings in Order No. 890, transmission providers must demonstrate that proposed deviations from the requirements of Order No. 1920 are ''consistent with or superior to'' the requirements in Order No. 1920.[2259]

918. We disagree with Dairyland's assertion that the Commission's use of the ''consistent with or superior to'' standard in Order No. 1920 is an unexplained departure from Commission precedent.[2260] To the contrary, in Order No. 1920, the Commission made no changes to the standard used to judge requested variations in the context of transmission planning, including in Order Nos. 888, 2000, 890, and 1000,[2261] and instead followed precedent in applying the ''consistent with or superior to'' standard of review to proposed new and existing variations from its transmission planning and cost allocation requirements.[2262] Rather, allowing for the use of the independent entity variation standard of review in this proceeding, as Dairyland and PJM request, would be a departure from this line of precedent and an importation of the independent entity variation standard from the interconnection context into the transmission planning context that would require further explanation.[2263] As discussed below, neither Dairyland nor PJM justify such a departure.

919. Further, we disagree with PJM's and Dairyland's claims that Order No. 1920 is internally inconsistent because it recognizes the need for regional flexibility while also including prescriptive requirements without allowing for independent entity variations.[2264] In a number of areas, Order No. 1920 provides transmission providers with the flexibility to accommodate regional differences, and this flexibility can be incorporated into the regional transmission planning requirements.[2265] Although in other areas the Commission provided less flexibility, we believe that the Commission struck a reasonable overall balance in Order No. 1920 between, on the one hand, transmission providers' need for flexibility in implementing Long-Term Regional Transmission Planning in their transmission planning regions and, on the other hand, ensuring that transmission providers adopt reforms that will result in transmission providers identifying, evaluating, and selecting more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs and thus Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.[2266]

920. We are unpersuaded by PJM's and Dairyland's arguments that the rationale for application of the independent entity variation standard to RTOs/ISOs in the interconnection context in Order No. 2003 applies equally to the circumstances of Order No. 1920.[2267] The requirements of Order No. 2003 were established to achieve greater standardization of interconnection terms and conditions and to address evidence of undue discrimination in interconnection processes.[2268] The Commission granted independent entities greater flexibility to deviate from the provisions of the *pro forma* OATT on the basis that these entities do not own generation and therefore face fewer incentives to act in an unduly discriminatory or preferential manner toward certain generators.[2269] That rationale does not apply to the requirements in Order No. 1920, which were adopted to address deficiencies in regional transmission planning processes, as those processes fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs and therefore to ensure just and reasonable rates.[2270] The need for regional transmission planning processes that meet the

[2258] *Id.* P 1768.

[2259] *Id.* P 1772 (citing Order No. 890, 118 FERC ¶ 61,119 at P 160).

[2260] Dairyland Rehearing Request at 3, 6.

[2261] 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.

[2262] Order No. 1920, 187 FERC ¶ 61,068 at P 1772.

[2263] *See FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515.

[2264] PJM Rehearing Request at 11–12; Dairyland Rehearing Request at 7.

[2265] For example, Order No. 1920 provides for flexibility such as: (1) allowing transmission providers to measure and use additional benefits in Long-Term Regional Transmission Planning; (2) allowing transmission providers to develop evaluation processes and selection criteria that can accommodate regional differences; and (3) declining to impose a selection requirement as transmission providers 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. *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 729, 924, 1027.

[2266] Order No. 1920, 187 FERC ¶ 61,068 at P 237.

[2267] PJM Rehearing Request at 13 n.60 (citing *Standardization of Generator Interconnection Agreements & Procs.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220, at PP 756, 759, *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; *Improvements to Generator Interconnection Procs. & Agreements,* Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at P 1764, *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, *errata notice,* 188 FERC ¶ 61,134 (2024)); Dairyland Rehearing Request at 5, 6 (citing MISO NOPR Reply Comments at 5–8).

[2268] Order No. 2003, 104 FERC ¶ 61,103 at PP 11–12.

[2269] *Id.* PP 822, 827; Order No. 2003–A, 106 FERC ¶ 61,220 at P 759.

[2270] *See* Order No. 1920, 187 FERC ¶ 61,068 at PP 87, 89.

Commission's requirements in Order No. 1920 applies to all transmission providers to the same extent regardless of their independence or complexity. Beyond noting the independence and complexity of RTOs/ISOs, neither PJM nor Dairyland have justified or offered evidence of why RTOs/ISOs should be treated differently than other transmission providers for purposes of compliance with Order No. 1920's requirements.

921. However, in light of PJM's and Dairyland's arguments, we clarify that, in analyzing Order No. 1920 compliance filings, we will apply the ''consistent with or superior to'' standard to proposed variations from *all* requirements of Order No. 1920 and not limit the standard to proposed variations from *pro forma* OATT provisions developed in Order No. 1920. Consistent with Commission practice,[2271] it is appropriate to apply the ''consistent with or superior to'' standard both to variations from *pro forma* OATT provisions and to variations from requirements not accompanied by *pro forma* OATT provisions (*i.e.,* those requirements that transmission providers must satisfy by developing or revising their own OATT provisions). The ''consistent with or superior to'' standard ''is a tool for ensuring that a proposed tariff revision will still meet the standards of the FPA'' despite varying from the ''minimum provisions necessary'' to ensure just, reasonable, and not unduly discriminatory or preferential Commission-jurisdictional rates.[2272] Both *pro forma* OATT provisions and requirements not accompanied by *pro forma* OATT provisions set ''common starting point[s]'' [2273] to ensure that Commission-jurisdictional rates satisfy the requirements of the FPA. The Commission will review proposed variations from requirements established in Order No. 1920 to ensure that they continue to meet the requirements of FPA sections 205 and 206.

922. In response to SPP's clarification request regarding its own Consolidated Planning Process, we reiterate that Order No. 1920 requires transmission providers to demonstrate that proposed deviations from Order No. 1920 are ''consistent with or superior to'' the requirements in Order No. 1920.[2274] To the extent that a transmission provider, like SPP, believes that its existing practices or potential provisions submitted as part of its compliance filing deviate from Order No. 1920's requirements, it must demonstrate that any such deviations, including any existing processes or OATT provisions, are consistent with or superior to the requirements of Order No. 1920.

923. We grant APPA's and TAPS' requests for clarification on the role of stakeholders in developing transmission providers' compliance filings. Specifically, we clarify that transmission providers must consult with their stakeholders to develop the processes, procedures, and OATT revisions necessary to comply with Order No. 1920.[2275] We note that this requirement is consistent with the approach that the Commission took in Order Nos. 890 and 1000.[2276]

924. We grant Large Public Power's clarification request regarding reciprocity. Order No. 1920 required that transmission providers that are not public utilities must adopt the requirements of Order No. 1920 as a condition of maintaining the status of their safe harbor tariffs or otherwise satisfy the reciprocity requirement of Order No. 888.[2277] As relevant to Large Public Power's clarification request, Order No. 888 provides that a non-public transmission provider may satisfy the reciprocity condition in one of three ways: (1) it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision of the *pro forma* OATT; (2) it may provide service to a public utility transmission provider under a bilateral agreement; or (3) it may seek a waiver of the reciprocity condition from the transmission provider.[2278]

925. Issues concerning effective dates are most appropriately addressed in specific compliance proceedings and, therefore, we decline to grant WIRES' clarification request. However, as explained in the Implementation of Long-Term Regional Transmission Planning section above, we set aside, in part, Order No. 1920's requirement that transmission providers in each transmission planning region must propose on compliance a date, no later than one year from the date on which initial filings to comply with the final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle [2279] and instead require transmission providers to propose on compliance a date, no later than *two* years from the date on which initial filings to comply with Order No. 1920 are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. Because we sustain Order No. 1920's requirement that transmission providers must propose an effective date for the OATT revisions necessary to comply with Order No. 1920 that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle,[2280] we note that this modification should help to address WIRES' concern.

926. We note that Versant Power's rehearing request has been

[2271] *See, e.g., Pub. Util. Transmission Rate Changes to Address Accumulated Deferred Income Taxes,* Order No. 864, 84 FR 65281 (Nov. 27, 2019), 169 FERC ¶ 61,139, at P 66 n.101 (2019), *order on reh'g,* Order No. 864–A, 85 FR 27681 (May 11, 2020), 171 FERC ¶ 61,033 (2020); *Uplift Cost Allocation & Transparency in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* Order No. 844, 83 FR 18134 (Apr. 25, 2018), 163 FERC ¶ 61,041, at P 103 (2018); *Settlement Intervals & Shortage Pricing in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* Order No. 825, 81 FR 42882 (June 30, 2016), 155 FERC ¶ 61,276, at PP 88, 90 (2016); Order No. 1000, 136 FERC ¶ 61,051 at P 583 n.452; *Demand Response Comp. in Organized Wholesale Energy Mkts.,* 76 FR 16658 (Mar. 24, 2011), Order No. 745, 134 FERC ¶ 61,187, at P 4 n.7; *order on reh'g & clarification,* Order No. 745–A, 137 FERC ¶ 61,215 (2011), *reh'g denied,* Order No. 745–B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n* v. *FERC,* 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. EPSA,* 577 U.S. 260; *Regional Transmission Orgs.,* Order No. 2000, 65 FR 810 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089, at 31,164 (1999) (amending 18 CFR 35.34(k)(1)–(2), (k)(4), (k)(6)–(7)), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty.* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[2272] *N.Y. State Elec. & Gas Corp.,* 78 FERC ¶ 61,114 (1997), *order on reh'g,* 82 FERC ¶ 61,209, at 61,822 n.4 (1998) (rejecting proposed deviations from the *pro forma* OATT and explaining that the ''consistent with or superior to'' inquiry does not impermissibly supplant or narrow the ''just and reasonable'' standard; rather, it evaluates whether a proposed deviation from the ''common starting point'' set out in a rule is consistent with or superior to that ''common starting point'' and therefore remains just and reasonable); *Commonwealth Edison Co.,* 83 FERC ¶ 61,274, at 62,143 (1998) (citing *N.Y. State Elec. & Gas Corp.,* 82 FERC at 61,822 & n.4). *See also Xcel Energy Servs. Inc.* v. *FERC,* 41 F.4th 548, 557–58 (D.C. Cir. 2022) (explaining that the Commission has used its ''broad discretion'' to craft the ''consistent with or superior to'' standard to assess whether proposed deviations are just, reasonable, and not unduly discriminatory).

[2273] *N.Y. State Elec. & Gas Corp.,* 82 FERC at 61,822 n.4.

[2274] Order No. 1920, 187 FERC ¶ 61,068 at P 1772.

[2275] We note that the requirement for transmission providers to consult with stakeholders to develop their compliance filings is separate from and in addition to Order No. 1920's requirement for transmission providers to conduct an Engagement Period for Relevant State Entities, as discussed in the Cost Allocation section above.

[2276] *See, e.g.,* Order No. 890, 118 FERC ¶ 61,119 at P 582; Order No. 1000, 136 FERC ¶ 61,051 at PP 151, 206, 227, 336, 588, 793.

[2277] Order No. 1920, 187 FERC ¶ 61,068 at P 1771 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63).

[2278] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63.

[2279] Order No. 1920, 187 FERC ¶ 61,068 at P 1072.

[2280] Order No. 1920, 187 FERC ¶ 61,068 at P 1768.

withdrawn.[2281] Nevertheless, we clarify that, consistent with Order No. 890 and Order No. 1000, entities that have existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888, as well as entities that have been granted waiver of the regional transmission planning requirements of Order No. 1000, do not also have to seek waiver of Order No. 1920.[2282] This clarification, however, is not meant to affect the ability of an entity that does not have an existing waiver to seek one. The Commission will consider requests for waiver of Order No. 1920 on a case-by-case basis from any entity that believes it meets the criteria for such waiver.

XIV. Overarching Logical Outgrowth Challenges

A. Requests for Rehearing

927. Several rehearing parties argue broadly that Order No. 1920 is not a logical outgrowth of the NOPR and therefore violates the notice-and-comment requirements of the APA.[2283] Arizona Commission asserts that the Commission failed to provide notice of and opportunity to comment on six ''fundamental'' changes between the NOPR and Order No. 1920 and that, because such changes are not logical outgrowths of the NOPR, the Commission violated the APA's notice-and-comment requirements, rendering Order No. 1920 unlawful.[2284] Specifically, Arizona Commission alleges that Order No. 1920, unlike the NOPR: (1) imposed preferential and corporate-driven costs on consumers in non-consenting states by requiring the filing of one or more *ex ante* cost allocation methods to apply to selected Long-Term Transmission Facilities; (2) mandated a specific set of ''planning criteria'' and purported benefits, which is ''simply a way of 'pre-cooking' outcomes''; (3) abandoned regional cost allocation principle (6); (4) effectively eliminated the use of a voluntary State Agreement Process; (5) left the CWIP incentive intact; and (6) made local transmission planning less transparent.[2285]

928. NRECA alleges that Order No. 1920 violated the APA's notice-and-comment requirements by: (1) mandating that transmission providers use a set of seven required benefits for evaluating and selecting Long-Term Regional Transmission Facilities; (2) imposing specific requirements for limited reevaluation of previously selected Long-Term Regional Transmission Facilities; (3) requiring that certain interconnection-related transmission needs must be evaluated for selection in existing Order No. 1000 regional transmission planning and cost allocation processes; (4) not requiring Long-Term Regional Transmission Planning cost allocation methods to comply with all of the Commission's six regional cost allocation principles; and (5) substantially diminishing the proposed role of state regulators in Long-Term Regional Transmission Planning and cost allocation.[2286] NRECA requests that the Commission withdraw Order No. 1920 and issue a supplemental NOPR because ''so many of [Order No. 1920's] key provisions'' are ''brand new'' and were not subjected to public comment.[2287]

929. Designated Retail Regulators contend that Order No. 1920 contains a number of significant changes that drastically depart from the NOPR, rendering the final rule ''surprisingly distant'' from and not a logical outgrowth of the NOPR, in violation of the APA's notice-and-comment requirements.[2288] Designated Retail Regulators add that Order No. 1920 ''is in essence a new rule that requires new opportunities for comment and input.'' [2289] Designated Retail Regulators claim that Order No. 1920 differs from the NOPR because Order No. 1920: (1) declined to adopt the NOPR proposal requiring transmission providers to seek the agreement of Relevant State Entities and substantially diminished Relevant State Entity involvement in cost allocation; (2) provided transmission providers complete discretion to decide whether to file a State Agreement Process or Long-Term Regional Transmission Cost Allocation Method in its tariff, even if agreed to by Relevant State Entities; and (3) did not require transmission providers to obtain the support of Relevant State Entities prior to proposing an evaluation process and selection criteria on compliance.[2290]

B. Commission Determination

930. We disagree with Arizona Commission's, Designated Retail Regulators', and NRECA's arguments that Order No. 1920 violates the APA's notice-and-comment requirements and is not a logical outgrowth of the NOPR. Relatedly, we decline to adopt NRECA's suggestion that the Commission withdraw Order No. 1920 in its entirety and issue a supplemental NOPR. As an initial matter, rehearing parties' conclusory arguments lack the specificity required to satisfy FPA section 313(a), which states that an ''application for rehearing shall set forth *specifically* the ground or grounds upon which such application is based.'' [2291] In claiming that Order No. 1920 violated the APA's notice-and-comment requirements, rehearing parties merely point to sections or provisions of Order No. 1920 that allegedly run afoul of those requirements and then assert, without support or further explanation, that Order No. 1920, as a whole, violates the APA's notice-and-comment provision. Arizona Commission, Designated Retail Regulators, and NRECA do not cite, and we are unaware of, any precedent supporting what appears to be their claim that cumulative logical outgrowth challenges to individual provisions would compel a finding that Order No. 1920, as a whole, is not a logical outgrowth of the NOPR. Accordingly, we reject this sweeping argument as lacking the specificity required on rehearing.[2292]

931. In any event, these arguments also lack merit. As discussed throughout this order, the individual provisions of

[2281] *See* Versant Power September 10, 2024 Notice of Withdrawal. Pursuant to Rule 216 of the Commission's Rules of Practice and Procedure, the withdrawal of any pleading is effective at the end of 15 days from the date of the filing if no motion in opposition to the notice of withdrawal is filed within that period and if the Commission takes no action disallowing withdrawal. 18 CFR 385.216. No motion in opposition to Versant Power's Notice of Withdrawal has been filed, and its request for rehearing accordingly is withdrawn.

[2282] Order No. 1000–A, 139 FERC ¶ 61,132 at P 753 & n.880 (2012); *see also* Order No. 890, 118 FERC ¶ 61,119 at P 135 n.105 (''The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the pro forma OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.'').

[2283] Arizona Commission Rehearing Request at 18–19 (citing 5 U.S.C. 706(2)(A), (C), (D)); Designated Retail Regulators Rehearing Request at 44, 49 (citing 5 U.S.C. 553); NRECA Rehearing Request at 6, 19 (citing 5 U.SC. 553).

[2284] Arizona Commission Rehearing Request at 18–19.

[2285] Arizona Commission Rehearing Request at 18–19. *Id.*

[2286] NRECA Rehearing Request at 6.

[2287] *Id.* at 19.

[2288] Designated Retail Regulators Rehearing Request at 46–50 (quoting *Int'l Union, United Mine Workers of Am.* v. *Mine Safety and Health Admin.*, 407 F.3d 1250, 1260 (D.C. Cir. 2005)).

[2289] *Id.* at 10.

[2290] *Id.* at 46–50.

[2291] 16 U.S.C. 825*l*(a) (emphasis added).

[2292] A rehearing request must set forth with specificity the grounds on which the request is based. 16 U.S.C. 825*l*(a); 18 CFR 385.713(c)(2) (2024); *see ZEP Grand Prairie Wind, LLC*, 183 FERC ¶ 61,150, at P 10; *Ind. Util. Regul. Comm'n* v. *FERC*, 668 F.3d at 738–40.

Order No. 1920, which certain rehearing parties claim the Commission adopted without adequate notice and opportunity to comment, are, in fact, logical outgrowths of the NOPR and otherwise satisfy the APA's notice-and-comment requirements.[2293] Thus, given that the constituent components of Order No. 1920 satisfy the APA's notice-and-comment requirements, the sum of those components—*i.e.,* Order No. 1920 as a whole—necessarily also satisfies these requirements, and rehearing parties have not shown otherwise.

XV. Information Collection Statement

932. The Paperwork Reduction Act[2294] requires each Federal agency to seek and obtain the Office of Management and Budget's (OMB) approval before undertaking a collection of information directed to 10 or more persons or contained in a rule of general applicability. OMB regulations require approval of certain information collection requirements contained in final rules published in the **Federal Register**.[2295] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this order on rehearing will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

933. *Summary:* On rehearing of Order No. 1920, the Commission is further revising the *pro forma* OATT to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements. This order on rehearing addresses arguments raised on rehearing, sets aside, in part, and clarifies Order No. 1920. The information collection requirements included in Order No. 1920 were previously approved by OMB under the FERC information collection number FERC–917: *Electric Transmission Facilities* (OMB Control No. 1902–0233). Order No. 1920 required transmission providers to conduct Long-Term Regional Transmission Planning to 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.

934. Previously, the Commission submitted to OMB the information collection requirements arising from Order No. 1920, and OMB approved those requirements. In this order on rehearing, the Commission makes five substantive changes to those requirements. In Order No. 1920, the Commission required transmission providers in each transmission planning region to incorporate seven specific categories of factors in the development of Long-Term Scenarios.[2296] Here, we set aside, in part, the requirement for transmission providers to incorporate seven specific categories of factors in the development of Long-Term Scenarios by excluding corporate commitments from Factor Category Seven. We no longer require transmission providers to separately identify corporate commitments as a factor in their development of Long-Term Scenarios given that the effects of such commitments will be sufficiently incorporated in Long-Term Regional Transmission Planning through the incorporation of other Factor Categories.

935. In Order No. 1920, the Commission required transmission providers in each transmission planning region to develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios.[2297] Here, we clarify that transmission providers, when requested by Relevant State Entities in a transmission planning region, are required to conduct a reasonable number of additional analyses or scenarios, to provide Relevant State Entities with information that they can use to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es).

936. In Order No. 1920, the Commission required transmission providers in each transmission planning region to revise the regional transmission planning process 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.[2298] In addition, the Commission required transmission providers to 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.[2299] Here, we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states' laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios.

937. In Order No. 1920, the Commission required transmission providers' evaluation processes, including selection criteria, to be transparent and not unduly discriminatory, and the Commission explained that transmission providers' evaluation of Long-Term Regional 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 Long-Term Regional Transmission Facilities) was selected or not selected.[2300] Here, we clarify that, once a transmission provider makes a selection decision, *i.e.,* for each selected Long-Term Regional Transmission Facility (or portfolio of such Facilities), and, if a State Agreement Process is used, once a cost allocation method is agreed upon, transmission providers must make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how those estimated costs will be allocated, by zone (*i.e.,* by transmission provider retail distribution service territory/footprint or RTO/ISO transmission pricing zone), and a quantification of those estimated benefits as imputed to each zone, as such benefits can be reasonably estimated.

938. In Order No. 1920, the Commission declined to require future Engagement Periods, but noted that transmission providers may hold future Engagement Periods if they believe that such periods would be beneficial.[2301] Here, we set aside Order No. 1920, in part, and require that, as part of

[2293] *See supra* Requirement for Transmission Providers to Use and Measure a Set of Seven Required Benefits section; Minimum Requirements section; Role of Relevant State Entities section; Reevaluation section; Transmission Planning Process Evaluation section; Obligation to File an *Ex Ante* Long-Term Regional Transmission Cost Allocation Method and Its Use as a Backstop section; Design and Operation of the Engagement Period section; Regional Cost Allocation Principles for Long-Term Regional Transmission Facilities section; General Benefits Requirements Related to Cost Allocation section; CWIP section.

[2294] 44 U.S.C. 3501–3521.

[2295] *See* 5 CFR 1320.12 (2024).

[2296] Order No. 1920, 187 FERC ¶ 61,068 at P 409.

[2297] *Id.* P 559.

[2298] *Id.* P 528.

[2299] *Id.* P 533.

[2300] *Id.* P 954.

[2301] Order No. 1920, 187 FERC ¶ 61,068 at P 1368.

transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the transmission provider to amend that method or process.

939. *Public Reporting Burden:* The estimated burden and cost for the requirements contained in this order on rehearing follow.

CHANGES DUE TO ORDER ON REHEARING IN DOCKET NO. RM21–17–001 [2302]

A. Area of modification	B. Annual number of respondents	C. Total annual estimated number of responses	D. Average burden hours & cost [2303] per response	E. Total estimated burden hours & total estimated cost (column C × column D)
FERC–917, Electric Transmission Facilities (OMB Control No. 1902–0233)				
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. Also require transmission providers to consult with Relevant State Entities prior to amending Long-Term Regional Transmission Cost Allocation Methods and/or State Agreement Process on file with the Commission.	48 transmission providers with OATTs.	48	*One Time:* 390 hours; $36,307 *Ongoing:* 39 hours per year; $3,631 per year.	*One Time:* 18,720 hours; $1,742,734. *Ongoing:* 1,872 hours per year; $174,274 per year.
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. 77 transmission providers without OATTs.	48 77	*One Time:* 0 hours; $0 *Ongoing:* 4,995 hours per year; $465,010 per year. *One Time:* 0 hours; $0 *Ongoing:* 202 hours per year; $18,805 per year.	*One Time:* 0 hours; $0. *Ongoing:* 239,760 hours per year; $22,320,457 per year. *One Time:* 0 hours; $0. *Ongoing:* 15,554 hours per year; $1,448,000 per year.
Total new burden for FERC 917 (due to Docket No. RM21–17–001).	48 transmission providers with OATTs. 77 transmission providers without OATTs.	48 77	*One Time:* 1,113 hours; $103,614. *Ongoing:* 5,329 hours per year; $496,103 per year. *One Time:* 20 hours; $1,862 *Ongoing:* 262 hours per year; $24,391 per year.	*One Time:* 53,424 hours; $4,973,495 *Ongoing:* 255,792 hours per year; $23,812,956 per year *One Time:* 1,540 hours; $143,366. *Ongoing:* 20,174 hours per year; $1,878,099 per year.
	Totals for all 125 transmission providers			*One Time:* 54,964 hours; $5,116,861. *Ongoing:* 275,966 hours per year; $25,691,055 per year.

940. Order No. 1920 estimated the ongoing total burden and cost for the 48 transmission providers with OATTs to be 230,160 total hours per year and $21,426,693 per year. Similarly, Order No. 1920 estimated the ongoing total burden and cost for the 77 transmission providers without OATTs to be 20,020 total hours per year and $1,863,757 per year. Given the prior discussion regarding excluding corporate commitments from Factor Category Seven and clarifications related to the potential for additional scenarios, additional consultation with Relevant State Entities, and posting or making available certain details of a selection decision on OASIS or other password-protected website, we estimate that these changes will result in an increase of burden hours. Therefore, we estimate that the ongoing total burden and cost, as revised herein, for the 48 transmission providers with OATTs to be 255,792 total hours per year and $23,812,956 per year. Similarly, we estimate that the ongoing total burden and cost, as revised herein, for the 77 transmission providers without OATTs to be 20,174 total hours per year and $1,878,099 per year. No other information collection requirements contained in Order No. 1920 are affected by this order on rehearing.

941. *Title:* Electric Transmission Facilities (FERC–917).

942. *Action:* Revision of collections of information in accordance with Docket No. RM21–17–001.

943. *OMB Control No.:* 1902–0233 (FERC–917).

944. *Respondents:* Transmission providers, including RTOs/ISOs.

945. *Frequency of Information Collection:* One time during Year 1. Occasional times during subsequent years, at least once every five years.

2302 In the table, Year 1 figures are one-time implementation hours and cost. ''Subsequent years'' show ongoing burdens and costs starting in Year 2.

2303 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.

946. *Necessity of Information:* The modifications in this order on rehearing will correct deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

947. *Internal Review:* We have reviewed the requirements set forth in this order on rehearing that impose information collection burdens and have determined that such requirements are necessary. These requirements 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.

948. Interested persons may obtain information on the reporting requirements by contacting Kayla Williams, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (*DataClearance@ferc.gov*) or telephone (202) 502–6468.

949. Comments concerning the collection of information and the associated burden estimates may also be sent to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to FERC–917 (OMB Control No. 1902–0233). Copies of the comments can be sent to the Commission (identified by Docket No. RM21–17–001 and the specific FERC collection number (FERC–917) electronically through *https://www.ferc.gov.* For those unable to file electronically, comment copies may be filed by USPS mail or by hand (including courier) delivery: Mail via U.S. Postal Service Only: Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. Or hand (including courier) delivery: Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

XVI. Environmental Analysis

950. 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.[2304] The Commission has categorically excluded certain actions from this requirement including approval of actions under FPA sections 205 and 206 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.[2305] Because the final rule promulgated by Order No. 1920, and revised herein, falls within this categorical exclusion, preparation of an environmental assessment or an environmental impact statement is not required.

XVII. Regulatory Flexibility Act

951. The Regulatory Flexibility Act of 1980 (RFA)[2306] generally requires a description and analysis of final rules 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,[2307] 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).[2308]

952. In Order No. 1920, the Commission, pursuant to RFA section 605(b), certified that the final rule would not have a significant economic impact on a substantial number of small entities.[2309] This order on rehearing does not disturb that conclusion. For the same reasons cited in Order No. 1920,[2310] the final rule, as revised herein, would not have a significant economic impact on a substantial number of small entities.

XVIII. Document Availability

953. 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 (*http://www.ferc.gov*).

954. 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.

955. 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.*

XIX. Effective Date

956. The changes to Order No. 1920 made in this order on rehearing and clarification are effective January 6, 2025.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Christie is concurring in part with a separate statement attached. Commissioner See is not participating.

Issued: November 21, 2024.

Debbie-Anne A. Reese,

Secretary.

Note: The following appendices will not appear in the Code of Federal Regulations.

[2304] *Reguls. Implementing the Nat'l Env'l Pol'y Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[2305] 18 CFR 380.4(a)(15).

[2306] 5 U.S.C. 601–612.

[2307] 13 CFR 121.201.

[2308] 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).

[2309] Order No. 1920, 187 FERC ¶ 61,068 at P 1788.

[2310] *See id.*

Appendix A: Abbreviated Names of Parties

Abbreviation	Rehearing party(ies)
Advanced Energy	Advanced Energy United.
Alabama Commission	Alabama Public Service Commission.
APPA	American Public Power Association.
Arizona Commission	Arizona Corporation Commission.
Cher Gilmore	Cher Gilmore.
City of New Orleans Council	Council of the City of New Orleans.
Clean Energy Associations	Advanced Energy United; American Clean Power Association; American Council on Renewable Energy; Solar Energy Industries Association.
Clean Energy Buyers	Clean Energy Buyers Association.
Competition Coalition	Electricity Transmission Competition Coalition; Resale Power Group of Iowa; LS Power Grid, LLC.
CTC Global	CTC Global Corporation.
Dairyland	Dairyland Power Cooperative.
Designated Retail Regulators	Louisiana Public Service Commission; Mississippi Public Service Commission; Arkansas Public Service Commission; South Dakota Public Utilities Commission.
Dominion	Dominion Energy Services, Inc.
E. Andrews	E. Andrews.
East Kentucky	East Kentucky Power Cooperative, Inc.
EEI	Edison Electric Institute.
Gary Andrews	Gary Andrews.
Georgia Commission	Georgia Public Service Commission.
Grid United	Grid United LLC.
Harvard ELI	Harvard Electricity Law Initiative.
Idaho Commission	Idaho Public Utilities Commission.
Identified Consumer Advocates	Office of the Massachusetts Attorney General; Connecticut Office of Consumer Counsel; Maine Office of Public Advocate; Maryland Office of People's Counsel; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers.
Illinois Commission	Illinois Commerce Commission.
Indicated PJM TOs	American Electric Power Service Corporation on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc.; 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 on behalf of its affiliates Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Delmarva Power & Light Company, PECO Energy Company, and Potomac Electric Power Company; 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, 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; UGI Utilities Inc.
Industrial Customers	American Forest & Paper Association; Coalition of MISO Transmission Customers; Industrial Energy Customers of America; PJM Industrial Customer Coalition.
Invenergy	Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; Invenergy Transmission LLC.
ITC	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC.
Large Public Power	Large Public Power Council.
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; 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.; Wolverine Power Supply Cooperative, Inc.
Minnesota Commission	Minnesota Public Utilities Commission.
Missouri Commission	Missouri Public Service Commission.
Montana Commission	Montana Public Service Commission.
NARUC	National Association of Regulatory Utility Commissioners.
NESCOE	New England States Committee on Electricity.
Northern Virginia	Northern Virginia Electric Cooperative, Inc.
NRECA	National Rural Electric Cooperative Association.
Ohio Commission Federal Advocate	Public Utilities Commission of Ohio's Office of the Federal Energy Advocate.
Ohio Consumers	Office of the Ohio Consumers Council.
Old Dominion	Old Dominion Electric Cooperative.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
PIOs	Appalachian Voices; Energy Alabama; Environmental Defense Fund; Environmental Law & Policy Center; Natural Resources Defense Council; North Carolina Sustainable Energy Association; Sierra Club; South Carolina Coastal Conservation League; Southern Alliance for Clean Energy; Southern Renewable Energy Association; Sustainable FERC Project.
PJM	PJM Interconnection, L.L.C.
PJM States	Organization of PJM States, Inc.

Abbreviation	Rehearing party(ies)
PJM Utilities	East Kentucky Power Cooperative, Inc.; Buckeye Power, Inc.; Old Dominion Electric Cooperative; Wabash Valley Power Association.
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; 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; Tennessee Valley Authority.
SPP	Southwest Power Pool, Inc.
State Regulatory Commissioners	Riley Allen (Commissioner, State of Vermont Public Utility Commission); Philip L. Bartlett II (Chair, Maine Public Utilities Commission); Kumar P. Barve (Commissioner, Maryland Public Service Commission); Eric Blank (Chairman, Colorado Public Utilities Commission); Alessandra Carreon (Commissioner, Michigan Public Service Commission); Michael T. Carrigan (Commissioner, Illinois Commerce Commission); David W. Danner (Chair, Washington Utilities and Transportation Commission); Megan Decker (Chair, Oregon Public Utilities Commission); Milt Doumit (Commissioner, Washington Utilities and Transportation Commission); Sarah Freeman (Commissioner, Indiana Utility Regulatory Commission); Andrew French (Chairperson, Kansas Corporation Commission); Marissa P. Gillett (Chairman, Connecticut Public Utilities Regulatory Authority); Hwikwon Ham (Commissioner, Minnesota Public Utilities Commission); Frederick H. Hoover (Chair, Maryland Public Service Commission); Darcie Houck (Commissioner, California Public Utilities Commission); Davante Lewis (Commissioner, Louisiana Public Service Commission); Ann McCabe (Commissioner, Illinois Commerce Commission); Valerie Means (Commissioner, Minnesota Public Utilities Commission); Stacey Paradis (Commissioner, Illinois Commerce Commission); Katherine Peretick (Commissioner, Michigan Public Service Commission); Les Perkins (Commissioner, Oregon Public Utilities Commission); Ann E. Rendahl (Commissioner, Washington Utilities and Transportation Commission); Alice Reynolds (President, California Public Utilities Commission); Michael T. Richard (Commissioner, Maryland Public Service Commission); Doug P. Scott (Chairman, Illinois Commerce Commission); Dan Scripps (Chair, Michigan Public Service Commission); Katie Sieben (Chair, Minnesota Public Utilities Commission); Bonnie A. Suchman (Commissioner, Maryland Public Service Commission); Joseph Sullivan (Vice Chair, Minnesota Public Utilities Commission); Letha Tawney (Commissioner, Oregon Public Utilities Commission); Emile C. Thompson (Chairman, District of Columbia Public Service Commission); Ted Trabue (Commissioner, District of Columbia Public Service Commission); John Tuma (Commissioner, Minnesota Public Utilities Commission).
Susann Rizzo	Susann Rizzo.
TAPS	Transmission Access Policy Study Group.
Undersigned States	Texas Attorney General; Alabama Attorney General; Arkansas Attorney General; Florida Attorney General; Georgia Attorney General; Idaho Attorney General; Iowa Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; North Dakota Attorney General; Oklahoma Attorney General; South Carolina Attorney General; South Dakota Attorney General; Tennessee Attorney General; Utah Attorney General.
Utah Commission	Utah Public Service Commission.
Vermont Commission	Vermont Public Utility Commission.
Versant Power	Versant Power.
Virginia Attorney General	Virginia Office of the Attorney General, Division of Consumer Counsel.
Virginia and North Carolina Commissions	Virginia State Corporation Commission; North Carolina Utilities Commission.
West Virginia Commission	Public Service Commission of West Virginia.
WIRES	WIRES.
Wyoming Commission	Wyoming Public Service Commission.

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 Nos. 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 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 Nos. 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. *Transmission Providers shall consult with and consider the positions of the Relevant State Entities, and any other entity authorized by a Relevant State Entity as its representative, as to whether a specific state policy must be accounted for as a factor within each category, how to account for the specific state policy in the development of Long-Term Scenarios, and how to adjust the treatment of the specific state policy across Long-Term Scenarios. When requested by Relevant State Entities in a transmission planning region, Transmission Providers shall conduct a reasonable number of additional analyses or scenarios to inform the application of Long-Term Regional Cost Allocation Method(s) or the development of cost allocation methods through the State Agreement Process(es). Transmission Providers shall not use any such additional analyses to identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities, or to meet the requirement that Transmission Providers estimate the costs and measure the benefits of Long-Term Regional Transmission Facilities for purposes of selection. Transmission Providers also shall not condition the selection of a Long-Term Regional Transmission Facility on the information provided in these additional analyses.*

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. *Once Transmission Providers make a selection decision, and, if a State Agreement Process is used, once a cost allocation method is agreed upon, Transmission Providers shall make available, on a password-protected portion of OASIS or other password-protected website, a breakdown of how the estimated costs of a Long-Term Regional Transmission Facility will be allocated, by zone, and a quantification of the Long-Term Regional Transmission Facility's estimated benefits as imputed to each zone, as such benefits can be reasonably estimated.*

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 *T*[t]ransmission *P*[p]rovider; and the circumstances under which, or the information necessary for, a *T*[t]ransmission *P*[p]rovider to file or to consider filing the agreed cost allocation.

Transmission Providers shall include in their Tariffs a description of how they will consult with Relevant State Entities (1) prior to amending the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es), or (2) if Relevant State Entities seek, consistent with their chosen method to reach agreement, for the Transmission Provider to amend that method or process. For a consultation initiated by the Transmission Providers, Transmission Providers shall document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities prior to filing their amendment. For a consultation initiated by Relevant State Entities, if the Transmission Providers choose not to propose any amendments to the Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es) preferred by Relevant State Entities during the required consultation, Transmission Providers shall document publicly on their OASIS or other public website the results of their consultation with Relevant State Entities, including an explanation for why they have chosen not to propose any amendments.

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 *P*[p]roviders 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 *(or in at least two individual interconnection studies for Transmission Providers that use a first-come, first-served serial generator interconnection process)* [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 *in two or more interconnection queue cycles (or two individual interconnection studies if the Transmission Provider uses a first-come, first-served serial generator interconnection process) have* [has]been withdrawn *and no more than five calendar years have passed between the date of an earlier interconnection request withdrawal and the date of a later interconnection request withdrawal;*[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[.]*; and*

(5) The interconnection request withdrawals associated with the repeatedly identified interconnection-related transmission need occurred no earlier than seven calendar years prior to the commencement date of the Order No. 1000 regional transmission planning and cost allocation cycle. The initial evaluation should occur in the first Order No. 1000 regional transmission planning and cost allocation cycle to occur after the effective date of the tariff revisions implementing this reform. The Transmission Provider need not evaluate an interconnection-related transmission need that has been evaluated in a previous Order No. 1000 regional transmission planning and cost allocation cycle.

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

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include cost allocation methods that satisfy the requirements set forth in Order Nos. 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. RM21–17–001

(Issued November 21, 2024)

CHRISTIE, Commissioner, *concurring in part:*

1. Today's order makes major changes to Order No. 1920. I am deeply grateful to my colleagues for their willingness to negotiate in good faith and ultimately to agree to these changes.

2. Order No. 1920 was based on purported authority derived from section 206 of the Federal Power Act (FPA).[1] Section 206 essentially requires that two prongs must be satisfied: First, the complainant, here the Commission, bears the burden to prove that existing rates—in this case, the transmission planning procedures of every transmission provider in the country, both Regional Transmission Organization (RTO)/Independent System Operator (ISO) and non-RTO/ISO—are unjust, unreasonable and/or unduly discriminatory or preferential. If the first prong (burden of proof) is met, in the second prong, the Commission must establish a just and reasonable replacement rate.[2] I concur with this order solely as to specific changes made in Order No. 1920–A to the replacement rate established in Order No. 1920.[3]

3. In my dissent to Order No. 1920, I made it clear that one of my major areas of disagreement was that it failed to fulfill the promise of a necessary and appropriate role for the states that was established in the Notice of Proposed Rulemaking (NOPR) that preceded Order No. 1920.[4] This promised state role was the primary reason I voted for the NOPR. As I have said repeatedly, state utility regulators are the first line of defense for their consumers and must have the authority to protect their consumers from unwarranted or excessive transmission costs, which are the fastest rising part of most consumers' monthly power bills and are reaching ever more burdensome levels.[5] The changes made today in Order No. 1920–A to the replacement rate set by Order No. 1920 go a *long* way towards restoring the state role to what the NOPR promised, and I am pleased to support these changes. Among them are the following positive and fundamental changes:

4. *Submission of State-Agreed Alternative.* In contrast to Order No. 1920, Order No. 1920–A requires that, if the states in a region agree to a cost allocation proposal, the transmission provider *must* include that agreement in its compliance filing. Furthermore, the Commission can choose the state agreement over the transmission provider's proposal.[6]

5. *Pre-Amendment State Consultation.* In addition, states *must* be consulted before the transmission provider considers any future changes to the cost allocation method or state agreement processes or if the states seek to amend the cost allocation method or state agreement processes.[7]

6. *Cost Allocation Flexibility.* In contrast to Order No. 1920, states are given far more flexibility to develop and agree to cost allocation processes and *ex ante* formulae that will suit their needs in diverse multistate regions such as PJM Interconnection, L.L.C. (PJM), Midcontinent Independent System Operator, Inc., and the Southeastern Regional Transmission Planning region. For example, states in PJM will now have explicit assurance that the PJM State Agreement Approach, in use for more than a decade, is preserved as an option for allocating to the sponsoring states the costs of public policy-driven projects, such as New Jersey's offshore wind and others that would not be selected for regional cost allocation.[8]

7. *State Input on Factors.* As part of the planning process, transmission providers must consult with the states before running the scenarios required by Order No. 1920 and must consider the views of the states as to how to account for and weigh the factors related to, or derived from, state public policies.[9]

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

[2] *Id.* (''Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, *the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. . . .*'' (emphasis added)).

[3] The specific changes which I support and to which I concur are described in the Appendix to this statement.

[4] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* NOPR, 179 FERC ¶ 61,028 (2022) (Christie, Comm'r, concurring at PP 5, 11, 14).

[5] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation,* Order No. 1920, 187 FERC ¶ 61,068 (2024) (Christie, Comm'r, dissenting at P 15 & nn.49–54).

[6] *See* Appendix at P 1.

[7] *Id.* P 2.

[8] *Id.* at P 7.

[9] *Id.* P 4.

8. *State Input on Baseline Scenarios.* Order No. 1920–A also clarifies that, for purposes of cost allocation, states in PJM and other diverse multistate regions can now choose a new *ex ante* process that will enable the states to request that the transmission provider run additional scenarios, including a baseline scenario that contains only optimal reliability or economic projects and excludes public policy-driven projects, so that states can compare the costs of the baseline scenario versus the larger, multi-driver scenarios that include public policy-driven projects. Most importantly, states can agree that the difference in costs between the baseline scenario and the larger, multi-driver scenarios that include projects derived from state policies or other policy goals will be allocated to the states whose policies are the source of the added costs and will not be regionally cost allocated.[10]

9. *Removal of Corporate Power Preferences and Cost-Shifting.* The requirement in Order No. 1920 that large corporate power-purchasing preferences must be a factor in planning long-term scenarios is explicitly removed.[11] That was one of the most unconscionable, special-interest driven features of Order No. 1920, directing transmission providers to plan hundreds of billions of dollars of transmission projects to subsidize the power-purchasing preferences of huge multinational corporations and shifting the costs to residential and small-business consumers already struggling to pay their monthly power bills.

10. *New Required Transparency.* Order No. 1920–A also emphasizes transparency and clarifies that the purported benefits of one or more states' public policies are clearly identified and quantified. This will enable states to determine whether they are being charged for other states' public policies, which benefits they are paying for, and how much.[12]

11. Collectively, these changes give the states a much bigger toolbox containing far more effective tools they can use to protect their consumers and the interests of their states. I urge state regulators to use them aggressively. Further, let me emphasize that, if the process of compliance—always complicated and challenging even with rulemakings of far smaller size and less complexity than this one—demonstrates that state flexibility and authority remain materially insufficient, further action by the Commission may become necessary.

12. And on the issue of compliance, I would add that the broad purpose of these changes is to allow the states sufficient flexibility and authority to protect their consumers from paying unfair or unnecessary costs. *That purpose should and must inform the compliance process.*

13. For these reasons, I respectfully concur to these changes established in Order No. 1920–A that are listed specifically in the Appendix. Again, I express my deep appreciation to my colleagues for their willingness to engage in good-faith negotiations leading to these important changes to the replacement rate.

For these reasons I respectfully concur in part.

Mark C. Christie,
Commissioner.

Appendix—Major Changes Incorporated in Order No. 1920–A

1. Require transmission providers to include in their filings state agreements on cost allocation, with enough detail so that any separate proposals can be considered and enable the Commission to adopt the states' agreement on compliance.

The order directs transmission providers to include in the transmittal of their compliance filings any Long-Term Regional Transmission Cost Allocation Method(s), and/or State Agreement Process(es) agreed to by Relevant State Entities, during the Engagement Period. The order also clarifies that transmission providers must include such cost allocation methods and/or State Agreement Processes in the transmittal of their compliance filings even when transmission providers propose on compliance a separate cost allocation method and/or declined to propose a State Agreement Process.

As part of this requirement, the order clarifies that transmission providers must include any and all supporting evidence and/or justification related to Relevant State Entities' agreed-upon cost allocation method and/or State Agreement Process that Relevant State Entities request that transmission providers include in their compliance filing. However, the order clarifies that transmission providers are not required to separately characterize Relevant State Entities' agreement or independently justify Relevant State Entities' preferred cost allocation.

When acting under FPA section 206, the Commission's statutory burden is to establish a just and reasonable and not unduly discriminatory replacement rate that is supported by substantial evidence and is the product of reasoned decision making. In satisfying this burden with respect to cost allocation, it is not the case that the Commission necessarily must adopt the transmission provider's proposal if that proposal complies with the final rule's requirements; rather, the Commission need only weigh competing views (if they exist), select an approach with adequate support in the record, and then intelligibly explain the reasons for its choice.

To be clear, this means that the Commission will consider the entire record—including the Relevant State Entities' agreed-upon cost allocation and the transmission provider's proposal. Specifically, when the Commission reviews transmission providers' compliance filings, the Commission is not required to accept a cost allocation proposal from a transmission provider simply because it may comply with Order No. 1920. Instead, the Commission may accept any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920.

2. Require transmission providers to revise their OATTs to add a requirement that they consult with Relevant State Entities before making a future filing under FPA section 205 to revise the Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process(es) that is on file.

The order requires that, as part of transmission providers' obligations with respect to transmission planning and cost allocation, transmission providers shall consult with Relevant State Entities prior to amending the *ex ante* Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process(es) agreed to by Relevant State Entities, or if Relevant State Entities seek to amend that method or process. The order requires transmission providers to document publicly on their website the results of that consultation prior to submitting their amendment. In addition, transmission providers must describe their reasoning for not using the results of the consultation with the Relevant State Entities. As an example, a jumpball framework, such as exists in MISO, SPP, and ISO–NE, could satisfy these requirements.

3. If Relevant State Entities request additional scenarios to inform their consideration of cost allocation methods, transmission providers shall develop those additional scenarios.

The order clarifies that transmission providers may develop additional scenarios, beyond the three Long-Term Scenarios that Order No. 1920 requires, to provide Relevant State Entities with information that they can use to inform the development of Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process(es). The order further clarifies that, when developing these additional scenarios used to inform cost allocation, transmission providers have the flexibility to depart from Order No. 1920's requirements related to the development of Long-Term Scenarios. For example, transmission providers may develop scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. The order further clarifies that, if the Relevant State Entities wish for the transmission provider to develop a reasonable number of additional scenarios for cost allocation, then the transmission providers will develop these scenarios.

4. Clarify that, while transmission providers have discretion over how to

[10] *Id.* PP 3, 8–11.

[11] *Id.* P 6.

[12] *Id.* P 10.

consider the effects of factors, transmission providers must consult with Relevant State Entities regarding factors related to state public policies.

The order clarifies that transmission providers must consult with and consider the positions of the Relevant State Entities as to how to account for factors related to state public policies in transmission planning assumptions. Specifically, the transmission provider shall consult with Relevant State Entities as to how to run the Long-Term Scenarios mandated by the final rule, as they may incorporate planning for state laws, policies, and regulations, including assumptions of transmission needs that may be attributable to, or derived from, state or local policies, such as assumptions about changing generation resources.

5. Allow states six additional months for the engagement period, upon request.

The order clarifies that, if Relevant State Entities, consistent with their chosen method to reach agreement, request additional time to complete cost allocation discussions, the Commission will extend the Engagement Period for up to an additional six months. The order finds that such an extension is warranted in that circumstance to ensure that Relevant State Entities have sufficient time to engage in fulsome discussions. The order also clarifies that the Commission will extend the relevant compliance deadlines, as appropriate, to accommodate an extension to the Engagement Period.

6. Exclude corporate commitments from Factor Category Seven.

The order eliminates the requirement for transmission providers to incorporate corporate commitments in Factor Category Seven when developing Long-Term Scenarios. The order finds that requiring transmission providers to consider corporate commitments when developing Long-Term Scenarios may introduce the risk of one class of transmission users cross-subsidizing another class of transmission users.

7. Expressly permit continued use of both new and/or existing state agreement approaches and similar voluntary measures.

The order clarifies that Order No. 1920 does not require reapproval of PJM's State Agreement Approach. The order clarifies that the Commission interprets PJM's State Agreement Approach to be supplemental to PJM's existing regional transmission cost allocation method. As a result, it is not in any way affected by the final rule. The order further clarifies (see #1 above) that, in their compliance filings, transmission providers shall include any State Agreement Process(es) agreed to by Relevant State Entities.

8. Transmission providers will allocate the costs of a Long-Term Regional Transmission Facility commensurate to its benefits.

The order clarifies that Order No. 1920 does not prevent transmission providers from recognizing different types of benefits and using them to allocate costs in proportion to those benefits. One potential cost allocation method that could be proposed to comply with Order No. 1920 would allocate costs commensurate with reliability and economic benefits region-wide, while allocating costs commensurate with additional benefits to a subset of states that agree to such cost allocation. Under this potential cost allocation method, these costs and benefits could be identified based on one or more additional scenarios run by the transmission planner for the purposes of informing cost allocation, *e.g.,* scenarios that consider the incremental cost of transmission needed to achieve state laws, policies, and regulations beyond the cost of transmission needed in the absence of those laws, policies, and regulations. For example, the cost allocation method agreed to by the Relevant State Entities may allocate those incremental costs to states with those applicable laws, policies, and regulations.

9. Clarify that states and/or transmission providers may define additional benefits to those enumerated in Order No. 1920.

Further, the order clarifies that costs borne by ratepayers must be roughly commensurate with benefits received. Transmission providers can consider additional benefits for cost allocation purposes, including as agreed to by Relevant State Entities and described elsewhere in this rule, provided that costs are allocated in a way that is at least roughly commensurate with estimated benefits.

10. Clarify that, for a selected project or tranche of projects, transmission providers shall, for each pricing zone, quantify the benefits and costs associated with such project or tranche.

The order clarifies that, for each selected project or tranche of projects, each transmission provider is required to make publicly available, on OASIS or other password-protected website, a breakdown of the allocated costs, by transmission pricing zone, and a quantification of the benefits imputed to each zone, as such benefits can be reasonably estimated.

11. Include, as an example of an approach that could be proposed to comply with Order No. 1920, the below *ex ante* cost allocation method language for Relevant State Entities. The inclusion of this example does not foreclose states from agreeing to other cost allocation approaches, each of which shall be evaluated on its own merits.

At the request of the Relevant State Entities in a multistate region, the following *ex ante* method for cost allocation may be proposed. In providing this example, the order is not foreclosing other approaches for allocating the costs of Long-Term Regional Transmission Facilities on either an *ex ante* or project-specific basis. Nor is the order suggesting that cost allocation methodologies must adopt a similar approach to this framework in order to comply with the requirements of this final rule:

(1) For purposes of cost allocation, the transmission providers shall run a scenario that otherwise complies with the Long-Term Regional Transmission Planning requirements of Order No. 1920 but does not include state laws, policies, and regulations and quantify the costs of the projects that would be selected from this scenario.

(2) The costs identified in (1) could be cost allocated according to an alternative *ex ante* formula filed by the transmission owners for the region.

(3) The amount representing the cost difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) shall be allocated as follows:

a. The transmission provider shall identify by state the specific state laws, policies, and regulations that were used to plan and select the facilities and shall quantify *by state* the specific costs of such facilities.

b. The costs identified in 3(a) shall be allocated solely to the state or states that are the sources of the policies used in planning and selection. The total difference between the costs of projects selected pursuant to the Long-Term Regional Transmission Planning process and (1) would be fully accounted for using this method of allocating costs among the states. The costs by zone *within* a state (Intrastate Costs) would be developed and filed by the applicable Transmission Owner(s).

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