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Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–23–000; Order No. 1000]

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. With respect to transmission planning, this Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider must participate in a regional transmission planning process that has: A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

DATES: *Effective Date:* This final rule will become effective on October 11, 2011.

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SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Order No. 1000

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I. Introduction

1. In this Final Rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements for public utility transmission providers.[1] The reforms herein are intended to improve

[1] 16 U.S.C. 824e (2006).

transmission planning processes and cost allocation mechanisms under the *pro forma* Open Access Transmission Tariff (OATT) to ensure that the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential. This Final Rule builds on Order No. 890,[2] in which the Commission, among other things, reformed the *pro forma* OATT to require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. After careful review of the voluminous record in this proceeding, the Commission concludes that the additional reforms adopted herein are necessary at this time to ensure that rates for Commission-jurisdictional service are just and reasonable in light of changing conditions in the industry. In addition, the Commission believes that these reforms address opportunities for undue discrimination by public utility transmission providers.

2. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The Commission appreciates the diversity of opinions expressed by commenters in response to the Notice of Proposed Rulemaking[3] as to whether, in light of the progress being made in many regions, further reforms to transmission planning processes and cost allocation mechanisms are necessary at this time. On balance, the Commission concludes that the reforms adopted herein are necessary for more efficient and cost-effective regional transmission planning. As discussed further below, the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost. The Commission concludes that it is appropriate to act now to ensure that its transmission planning processes and cost allocation requirements are adequate to allow public utility transmission providers to address these challenges more efficiently and cost-effectively. In reaching this conclusion, the Commission has balanced competing interests of various segments of the industry and designed a package of reforms that, in our view, will support the development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and allow for consideration of transmission needs driven by public policy requirements established by state or federal laws or regulations (Public Policy Requirements). By ''state or federal laws or regulations,'' we mean 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.

3. Through this Final Rule, we conclude that the existing requirements of Order No. 890 are inadequate. Public utility transmission providers are currently under no affirmative obligation to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes. Similarly, there is no requirement that public utility transmission providers consider transmission needs at the local or regional level driven by Public Policy Requirements. Nonincumbent transmission developers seeking to invest in transmission can be discouraged from doing so as a result of federal rights of first refusal in tariffs and agreements subject to the Commission's jurisdiction. While neighboring transmission planning regions may coordinate evaluation of the reliability impacts of transmission within their respective regions, few procedures are in place for identifying and evaluating the benefits of alternative interregional transmission solutions. Finally, many cost allocation methods in place within transmission planning regions fail to account for the beneficiaries of new transmission facilities, while cost allocation methods for potential interregional facilities are largely nonexistent.

4. We correct these deficiencies by enhancing the obligations placed on public utility transmission providers in several specific ways. While focused on discrete aspects of the transmission planning and cost allocation processes, the specific reforms adopted in this Final Rule are intended to achieve two primary objectives: (1) Ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them. In addition, this Final Rule addresses interregional coordination and cost allocation, to achieve the same objectives with respect to possible transmission solutions that may be located in a neighboring transmission planning region.

5. Certain requirements of this Final Rule distinguish between ''a transmission facility in a regional transmission plan,'' and ''a transmission facility selected in a regional transmission plan for purposes of cost allocation.''[4] A ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' is one that has been selected, pursuant to a Commission-approved regional transmission planning process, as a more efficient or cost-effective solution to regional transmission needs. As discussed in more detail below, this distinction is an essential component of this Final Rule.

6. Turning to the specific discrete reforms we adopt today, we first require public utility transmission providers to participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. This requirement builds on the transmission planning principles adopted by the Commission in Order No. 890, and the regional transmission planning processes developed in response to this Final Rule must satisfy those principles. These processes must result in the development of a regional transmission plan. As part of our reforms, we also require that the regional transmission planning process, as well as the underlying local transmission planning processes of public utility transmission providers, provide an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that requiring each local and regional transmission planning process to provide this opportunity is necessary to ensure that transmission planning processes identify and evaluate transmission needs driven by relevant

[2] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *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).

[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,660 (2010) (Proposed Rule).

[4] *See infra* P 0.

Public Policy Requirements, and support more efficient and cost-effective achievement of those requirements.

7. Second, we direct public utility transmission providers to remove from their OATTs or other Commission-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation.[5] We conclude that leaving federal rights of first refusal in place for these facilities would allow practices that have the potential to undermine the identification and evaluation of a more efficient or cost-effective solution to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. To implement the elimination of such federal rights of first refusal, we adopt below a framework that requires, among other things, the development of qualification criteria and protocols for the submission and evaluation of transmission proposals. In addition, as described in section III.B.3, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations. This requirement, however, applies only to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and not, for example, to transmission facilities in local transmission plans that are merely ‘‘rolled up’’ and listed in a regional transmission plan without going through an analysis at the regional level, and therefore, not eligible for regional cost allocation.

8. Third, we require public utility transmission providers to improve coordination across regional transmission planning processes by developing and implementing, through their respective regional transmission planning process, procedures for joint evaluation and sharing of information regarding the respective transmission needs of transmission planning regions and potential solutions to those needs. These procedures must provide for the identification and joint evaluation by neighboring transmission planning regions of interregional transmission facilities to determine if there are more efficient or cost-effective interregional transmission solutions than regional solutions identified by the neighboring transmission planning regions. To facilitate the joint evaluation of interregional transmission facilities, we require the exchange of planning data and information between neighboring transmission planning regions at least annually.

9. Finally, we require public utility transmission providers to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. We also require public utility transmission providers in each transmission planning region to have, together with the public utility transmission providers in a neighboring transmission planning region, a common method, or set of methods, for allocating the costs of a new interregional transmission facility that is jointly evaluated by the two or more transmission planning regions in their interregional transmission coordination procedures. Given the fact that a determination by the transmission planning process to select a transmission facility in a plan for purposes of cost allocation will necessarily include an evaluation of the benefits of that facility, we require that transmission planning and cost allocation processes be aligned. Further, all regional and interregional cost allocation methods must be consistent with regional and interregional cost allocation principles, respectively, adopted in this Final Rule. Nothing in this Final Rule requires either interconnectionwide planning or interconnectionwide cost allocation.

10. The cost allocation reforms adopted today, and the cost allocation principles that each proposed regional and interregional cost allocation method or methods must satisfy, seek to address the potential opportunity for free ridership inherent in transmission services, given the nature of power flows over an interconnected transmission system. In particular, the principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits.[6] In addition, the Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method.

11. As noted above, the various specific reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that those transmission facilities selected in a regional transmission plan for purposes of cost allocation are the more efficient or cost-effective solutions available. At its core, the set of reforms adopted in this Final Rule require the public utility transmission providers in a transmission planning region, in consultation with their stakeholders, to create a regional transmission plan. This plan will identify transmission facilities that more efficiently or cost-effectively meet the region’s reliability, economic and Public Policy Requirements. To meet such requirements more efficiently and cost-effectively, the regional transmission plan must reflect a fair consideration of transmission facilities proposed by nonincumbents, as well as interregional transmission facilities. The regional transmission plan must also include a clear cost allocation method or methods that identify beneficiaries for each of the transmission facilities selected in a regional transmission plan for purposes of cost allocation, in order to increase the likelihood that such transmission facilities will actually be constructed.

12. The transmission planning and cost allocation requirements in this Final Rule, like those of Order No. 890, are focused on the transmission planning *process,* and not on any substantive outcomes that may result from this process. Taken together, the requirements imposed in this Final Rule work together to remedy deficiencies in the existing requirements of Order No. 890 and enhance the ability of the transmission grid to support wholesale power markets. This, in turn, will fulfill our statutory obligation to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.

13. We acknowledge that public utility transmission providers in some

[5] *See infra* P 0.

[6] However, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead rely on participant funding. *See infra* P 723–729.

transmission planning regions already may have in place transmission planning processes or cost allocation mechanisms that satisfy some or all of the requirements of this Final Rule. Our reforms are not intended to undermine progress being made in those regions, nor do we intend to undermine other planning activities that are being undertaken at the interconnection level. Rather, the Commission is acting here to identify a minimum set of requirements that must be met to ensure that all transmission planning processes and cost allocation mechanisms subject to its jurisdiction result in Commission-jurisdictional services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

14. The Commission appreciates the significant work that will go into the preparation of compliance proposals in response to this Final Rule. To assist public utility transmission providers in their efforts to comply, the Commission directs its staff to hold informational conferences within 60 days of the effective date of this Final Rule to review and discuss the requirements imposed herein with interested parties. Moreover, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

A. Order Nos. 888 and 890

15. In Order No. 888,[7] issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service to others on a basis that is inferior to that which they provide to themselves.[8] Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 and the accompanying *pro forma* OATT implemented open access to transmission facilities owned, operated, or controlled by a public utility.

16. As part of those reforms, Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. For example, the *pro forma* OATT required a public utility transmission provider to account for the needs of its network customers in its transmission planning activities on the same basis as it provides for its own needs.[9] The *pro forma* OATT also required that new facilities be constructed to meet the transmission service requests of long-term firm point-to-point customers.[10] While Order No. 888–A went on to encourage utilities to engage in joint and regional transmission planning with other utilities and customers, it did not require those actions.[11]

17. In early 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT that the Commission identified based on the decade of experience since the issuance of Order No. 888. Among other things, the Commission found that *pro forma* OATT obligations related to transmission planning were insufficient to eliminate opportunities for undue discrimination in the provision of transmission service. The Commission stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner. Among other shortcomings in the *pro forma* OATT, the Commission pointed to the lack of clear criteria regarding the transmission provider's planning obligation; the absence of a requirement that the overall transmission planning process be open to customers, competitors, and state commissions; and the absence of a requirement that key assumptions and data underlying transmission plans be made available to customers.

18. In light of these findings, one of the primary goals of the reforms undertaken in Order No. 890 was to address the lack of specificity regarding how stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in transmission planning activities, the Commission required each public utility transmission provider to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to its OATT (Attachment K). The Order No. 890 transmission planning principles are: (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.[12]

19. The transmission planning reforms adopted in Order No. 890 apply to all public utility transmission providers, including Commission-approved RTOs and ISOs. The Commission stated that it expected all non-public utility transmission providers to participate in the local transmission planning processes required by Order No. 890, and that reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as public utility transmission providers.[13] The Commission stated that a coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. However, the Commission did not invoke its authority under FPA section 211A, which allows the Commission to require an unregulated transmitting utility (*i.e.,* a non-public utility transmission provider) to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[14] The Commission instead stated that if it found, on the appropriate record, that non-public utility transmission providers are not participating in the transmission planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

20. On December 7, 2007, pursuant to Order No. 890, most public utility transmission providers and several non-public utility transmission providers submitted compliance filings that describe their proposed transmission

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *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 Policy Study Group* v. *FERC,* 225 F.3d 667 (DC Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[8] Order No. 888, FERC Stats. & Regs. at 31,682.

[9] *See* Section 28.2 of the *pro forma* OATT.

[10] *See* Sections 13.5, 15.4, and 27 of the *pro forma* OATT.

[11] Order No. 888–A, FERC Stats. & Regs. at 30,311.

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418–601.

[13] *Id.* P 441.

[14] FPA section 211A(b) provides, in pertinent part, that ''the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services—(1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' 16 U.S.C. 824j.

planning processes.[15] The Commission addressed these filings in a series of orders that were issued throughout 2008. Generally, the Commission accepted the compliance filings to be effective on December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning processes to satisfy the nine Order No. 890 transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

21. As a result of these compliance filings, regional transmission organization (RTO) and independent system operators (ISO) have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions also have made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional transmission planning processes.[16] These improvements to transmission planning processes have given stakeholders the ability to participate in the identification of regional transmission needs and corresponding solutions, thereby facilitating the development of more efficient and cost-effective transmission expansion plans. This Final Rule expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters.

B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation

22. In several of the above-noted orders issued in 2008 and early 2009 on filings submitted to comply with the Order No. 890 transmission planning requirements, the Commission stated that it would continue to monitor implementation of these transmission planning processes. The Commission also announced its intention to convene regional technical conferences in 2009.

23. Consistent with the Commission's announcement, Commission staff in September 2009 convened three regional technical conferences in Philadelphia, Atlanta, and Phoenix, respectively. The focus of the technical conferences was to: (1) Determine the progress and benefits realized by each transmission provider's transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnectionwide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing transmission planning processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities and the integration of large amounts of location-constrained generation. Issues discussed at the technical conferences included the effectiveness of the current transmission planning processes, the development of regional and interregional transmission plans, and the effectiveness of existing cost allocation methods used by transmission providers and alternatives to those methods.

24. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments.[17] The October 2009 Notice presented numerous questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission. In response to the October 2009 Notice, the Commission received 107 initial comments and 45 reply comments.

C. Additional Developments Since Issuance of Order No. 890

25. Other developments with important implications for transmission planning have occurred amid the above-noted Order No. 890 compliance efforts on transmission planning and as the Commission gathered information through the technical conferences and the October 2009 Notice discussed above.

26. For example, in February 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), which provided $80 million for the U.S. Department of Energy (DOE), in coordination with the Commission, to support the development of interconnection-based transmission plans for the Eastern, Western, and Texas interconnections. In seeking applications for use of those funds, DOE described the initiative as intended to: Improve coordination between electric industry participants and states on the regional, interregional, and interconnectionwide levels with regard to long-term electricity policy and planning; provide better quality information for industry planners and state and federal policymakers and regulators, including a portfolio of potential future supply scenarios and their corresponding transmission requirements; increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and facilitate and accelerate development of renewable energy or other low-carbon generation resources.[18]

27. In December 2009, DOE announced award selections for much of this ARRA funding. In each interconnection, applicants awarded funds under what DOE defined as Topic A are responsible for conducting interconnection-level analysis and transmission planning. Applicants awarded funds under Topic B are to facilitate greater cooperation among states within each interconnection to guide the analyses and planning performed under Topic A.[19] Broad participation in sessions to date related to this initiative suggest that the availability of federal funds to pursue these goals has increased awareness of the potential for greater coordination among regions in transmission planning.

28. In describing the activities undertaken under this transmission analysis and planning initiative, DOE staff leading the project has explained that its activities are based on the premise that the electricity industry faces a major long-term challenge in ensuring an adequate, affordable and environmentally sensitive energy supply and that an open, transparent, inclusive, and collaborative process for transmission planning is essential to securing this energy supply.[20] To that end, DOE staff has stressed that all stakeholders need to be involved in

[15] A small number of public utility transmission providers were granted extensions.

[16] The regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are the North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.

[17] Federal Energy Regulatory Commission, Notice of Request for Comments, Transmission Planning Processes under Order No. 890; Docket No. AD09–8–000, October 8, 2009 (October 2009 Notice).

[18] Department of Energy, *Recovery Act—Resource Assessment and Interconnection-Level Transmission Analysis and Planning Funding Opportunity Announcement,* at 5–6 (June 15, 2009).

[19] *Id.* at 4–8.

[20] Department of Energy, ''*DOE Initiative Regarding Interconnection-Level Transmission Analysis and Planning;*'' presented at the NGA Transmission Roundtable by David Meyer of DOE's Office of Electricity Delivery and Energy Reliability, January 25, 2011.

assessing options to meeting this future need and that ARRA funds are ''seed money'' to help establish capabilities to address transmission planning issues.[21] In DOE staff's view, the goal of this funding is to help planners develop a portfolio of long-term energy supply and demand for future needs and associated transmission requirements to assess the implications of these alternative future energy scenarios and identify facilities appropriate for consideration in the development of long-term infrastructure plans. Key deliverables of the DOE-funded planning activities are 10- and 20-year plans that analyze the transmission needs of each interconnection under a range of scenarios.

29. While the results of these planning efforts are not yet available, there is already a growing body of evidence that, in DOE's words, ''[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario.'' [22] In its most recent Long-Term Reliability Assessment, North American Electric Reliability Corporation (NERC) identifies 39,000 circuit-miles of projected high-voltage transmission over the next 10 years.[23] NERC estimates that roughly a third of these transmission facilities will be needed to integrate variable and renewable generation.[24] Much of this investment in renewable generation is being driven by renewable portfolio standards adopted by states. Some 28 states and the District of Columbia have now adopted renewable portfolio standard measures. In addition, there are 9 states with non-binding goals. The key difference is that the states with requirements usually have financial penalties for non-compliance, known as alternative compliance payments. States with non-binding goals usually have no financial penalty, although some have instituted financial incentives for meeting the goal (*e.g.,* Virginia). These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures. Most of these portfolio standards are set to increase annually, further amplifying the potential need for transmission facilities.

[21] *Id.*

[22] Department of Energy, *20% Wind Energy by 2030,* at 93 (July 2008).

[23] NERC 2010 Assessment at 22.

[24] *Id.* at 24.

II. The Need for Reform

A. Proposed Rule

30. In light of the changes occurring within the electric industry, and based on the Commission's experience in implementing Order No. 890 and comments submitted in response to the October 2009 Notice, the Commission issued the Proposed Rule on June 17, 2010 identifying further reforms to the *pro forma* OATT in the areas of transmission planning and cost allocation. These reforms, discussed in detail below, were aimed at ensuring that the transmission planning and cost allocation requirements established in Order No. 890 continue to result in the provision of Commission-jurisdictional service at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission received roughly 5,700 pages of initial and reply comments in response. Based on these comments, the Commission concludes that amendment of the transmission planning and cost allocation requirements established in Order No. 890 is necessary at this time to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

31. The Commission noted in the Proposed Rule that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. However, the Commission explained that changes in the nation's electric power industry since issuance of Order No. 890 required the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. The Commission stated its intention was not to disrupt the progress being made with respect to transmission planning and investment in transmission infrastructure, but rather to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

B. Comments

32. A number of commenters generally support the Commission's decision to initiate a rulemaking proceeding that proposes reforms to the transmission planning and cost allocation processes.[25] Several of these commenters state that inadequate transmission planning and cost allocation processes have impeded the development of transmission infrastructure.[26]

33. For example, Transmission Dependent Utility Systems state that they support the primary objective of the Proposed Rule to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale markets and ensure that jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. Exelon argues that the current system of disconnected priorities and mixed criteria is simply not working. Pennsylvania PUC encourages the Commission to eliminate the current uncertainty regarding planning and paying for future transmission expansion and upgrades.

34. MidAmerican adds that transmission has grown from an industry sector focused on rebuilds, reliability improvements on existing infrastructure, and construction of generation-dependent interconnection facilities, to one where new and upgraded transmission infrastructure is necessary to effectuate the expansion of regional power markets, promote a more reliable transmission system, accommodate increasing reliance on renewable generation sources, and address the uncertainty of the future role of existing conventional generation. AWEA contends that existing processes for planning and paying for transmission are not sufficient to meet the emerging challenges to the transmission system. AWEA argues that many cost allocation methodologies, as they are applied today, are flawed, which together with the fragmented and short-term transmission planning regimes prevalent today, have often

[25] *E.g.,* 26 Public Interest Organizations; AEP; American Transmission; AWEA; Anbaric and PowerBridge; Atlantic Grid; Colorado Independent Energy Association; Conservation Law Foundation; Duke; East Texas Cooperatives; Energy Future Coalition; Exelon; Gaelectric; Green Energy Express and 21st Century; Iberdrola Renewables; Imperial Irrigation District; Integrys; ISO New England; ITC Companies; MidAmerican; Multiparty Commenters; National Audubon Society; National Grid; New York ISO; New York PSC; NextEra; Northwest & Intermountain Power Producers Coalition; Old Dominion Electric Cooperative; Pennsylvania PUC; Ignacio Perez-Arriaga; Senators Dorgan and Reid; SPP; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; Western Grid Group; Wind Coalition; WIRES; and Wisconsin Electric.

[26] *E.g.,* AEP; AWEA; Exelon; Iberdrola Renewables; ITC Companies; MidAmerican; and NextEra.

stifled investment in, or otherwise led to the inefficient use and inadequate expansion of the nation's transmission network. Senators Dorgan and Reid state that better coordination of regional transmission planning and clarifying cost allocation are two important steps in overcoming hurdles to developing the nation's vast renewable energy resources and providing clean energy jobs. National Grid contends that the creation of a robust transmission system is imperative to achieving important policy goals, environmental objectives, market efficiencies, and the integration of renewable and distributed resources into electric power markets.

35. NextEra agrees on reply that there is a need for generic reform at this time, stating that there is a sufficient basis for the Commission to proceed with a rulemaking proceeding and that there is ample evidence of the pressing need to enhance the transmission grid. NextEra states that the Proposed Rule demonstrates how and why existing transmission planning and cost allocation rules are inadequate.

36. A number of commenters provide specific examples of developments that further demonstrate the need for reform. Colorado Independent Energy Association states that, in WestConnect, regional transmission providers are not ignoring the problem of transmission constraints, but that development of transmission facilities is not being undertaken and, second, transmission facilities are not being properly sized. In its view, the problems can be traced to the absence of cost allocation methods or the lack of means for identifying the most needed projects and pursuing them to completion.

37. Iberdrola Renewables contends that the lack of transmission expansion in the MISO has led to significant congestion in areas with extensive operating wind generation. It states that the MISO has reported that wind curtailments primarily caused by congestion averaged five percent for the first six months of 2010 compared with 2 percent on average in 2009. Exelon adds that the lack of coordination between the MISO and PJM transmission planning regions has resulted in a significant increase in the out-of-merit dispatch of generation on the Commonwealth Edison system to maintain NERC reliability requirements. Exelon states that these events have increased from 31 in 2006 to 280 in 2009, and they result in higher costs on the system and excessive wear and tear on equipment.

38. Brattle Group states that it has identified approximately 130 mostly conceptual and often overlapping planned transmission projects throughout the country with a total cost of over $180 billion.[27] It contends that a large portion of these projects will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes. Brattle Group states that many of the benefits associated with economic and public policy projects are difficult to quantify and, without changes to transmission planning and cost allocation processes, many of these projects may fail to gain the needed support for approval, permitting, and cost recovery.

39. Other commenters question the need for Commission action at this time, urging the Commission to be more rigorous in its proposed findings and holdings and arguing that the Proposed Rule is not supported by substantial evidence.[28] Large Public Power Council disagrees with the Commission's assertions in the Proposed Rule that state that renewable portfolio standards have contributed to the need for new transmission. Large Public Power Council states that the Commission offers no factual evidence to support its assertions [29] and that the evidence available actually weighs against the Commission. Large Public Power Council states that renewable portfolio standards have not increased meaningfully since the Commission issued Order No. 890. Furthermore, Large Public Power Council cites a report produced by Edison Electric Institute that states that the members of Edison Electric Institute are making significant and growing investments in transmission infrastructure, including interstate projects and projects that will facilitate the integration of renewable resources. Moreover, Large Public Power Council contends that the Commission offers no evidence that the reforms of the type proposed are a necessary or satisfactory solution to the perceived problem.

40. Replying to commenters that stress the need for reform, discussed above, several commenters argue that none provides evidence supporting the need for a nationwide rule at this time.[30] Ad Hoc Coalition of Southeastern Utilities states that commenters such as Exelon and Multiparty Commenters provide only anecdotes supporting their contention that there is a need to reform transmission planning and cost allocation processes, and argues that these individual issues can be addressed on a case-specific basis rather than through generic rules. Joined by Southern Companies, Ad Hoc Coalition of Southeastern Utilities argues that factual allegations of transmission expansion deficiencies are not applicable to the Southeast, pointing to their robust transmission grid. They state that, to the extent these allegations raise issues for other regions, then they should be addressed within those regions and that these issues do not merit nationwide treatment.[31] Additionally, Ad Hoc Coalition of Southeastern Utilities asserts that existing planning processes under Order No. 890 have not been in place long enough to determine whether reforms are needed, and other commenters assert that existing planning processes are working well.[32] PSEG Companies assert that the real issue is the siting process, which makes it difficult to actually build projects even if they are truly needed to maintain system reliability.

41. Indianapolis Power & Light states that the Commission has not undertaken any type of analysis to find out what needs to be built, where it needs to be built, and who needs to build it. Indianapolis Power & Light asserts that the Commission has not looked closely at the different regions of the country to determine which areas could benefit from the new proposed reforms. Indianapolis Power & Light states that the Commission has not sufficiently demonstrated a need for this rulemaking and should consider whether its broad-based application is necessary in the first place. San Diego Gas & Electric recommends that the Commission not issue a Final Rule at this time, arguing

[27] Brattle Group, Attachment at 5.

[28] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Salt River Project; Large Public Power Council (each commenter cites *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831 (DC Cir. 2006) (*National Fuel*)); Large Public Power Council (citing *Associated Gas Distrib.* v. *FERC,* 824 F.2d 981 (DC Cir. 1985) (*Associated Gas Distributors*)); PSEG Companies; Salt River Project; and San Diego Gas & Electric.

[29] Citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148–154 (Large Public Power Council cites to the following two assertions in the Proposed Rule: ''Further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions.'' (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 150); and ''* * * the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities across several utility and/or RTO or ISO regions.'' (Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 151)).

[30] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; San Diego Gas & Electric; and Southern Companies.

[31] Ad Hoc Coalition of Southeastern Utilities, Large Public Power Council and Southern Companies cite to *Associated Gas Distributors,* 824 F.2d 981 at 1019.

[32] *E.g.,* PSEG Companies and Salt River Project.

that doing so based on the current proposals would disrupt and delay the build-out of the transmission grid and cause transmission providers to redirect resources away from that primary objective to the inevitable legal and compliance challenges to this Final Rule.

C. Commission Determination

42. The Commission concludes that it is appropriate to act at this time to adopt the package of reforms contained in this Final Rule. Our review of the record, as well as the recent studies discussed above, indicates that the transmission planning and cost allocation requirements established in Order No. 890 provide an inadequate foundation for public utility transmission providers to address the challenges they are currently facing or will face in the near future. Although focused on discrete aspects of transmission planning and cost allocation processes, the reforms adopted in this Final Rule are designed to work together to ensure an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that transmission facilities in the transmission plan will move forward to construction. The Commission's actions today therefore will enhance the ability of the transmission grid to support wholesale power markets and, in turn, ensure that Commission-jurisdictional transmission services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential.

43. The Commission acknowledges that transmission planning processes have seen substantial improvements, particularly at the regional level, in the relatively short time since the issuance of Order No. 890. Moreover, as some commenters note, transmission planning processes in many regions continue to evolve as public utility transmission providers and stakeholders explore new ways of addressing mutual needs. However, the Commission is concerned that the existing requirements of Order No. 890 regarding transmission planning and cost allocation are insufficient to ensure that this evolution will occur in a manner that ensures that the rates, terms and conditions of service by public utility transmission providers are just and reasonable and not unduly discriminatory. As a number of commenters contend, inadequate transmission planning and cost allocation requirements may be impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development due to a lack of coordination, all of which contributes to unnecessary congestion and difficulties in obtaining more efficient or cost-effective transmission service.

44. The increase in transmission investment in recent years, as noted in the report produced by Edison Electric Institute and cited by Large Public Power Council,[33] does not mitigate our need to act at this time. To the contrary, as discussed below, the recent increase in transmission investment supports issuance of this Final Rule to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions moving forward. In its report, Edison Electric Institute states that its members have steadily increased investment in transmission over the period from 2001 to 2009, resulting in approximately $55.3 billion in new transmission facilities.[34] NERC confirms the recent increase in investment in its 2010 Long-Term Reliability Assessment.[35] This trend appears to be only the beginning of a longer-term period of investment in new transmission facilities. In another report commissioned by Edison Electric Institute, Brattle Group suggests that approximately $298 billion of new transmission facilities will be required over the period from 2010 to 2030.[36] NERC's analysis of the past 15 years of transmission development confirms the significant increase in future transmission investment, showing that additional transmission planned for construction during the next five years nearly triples the average miles that have historically been constructed.[37]

45. The need for additional transmission facilities is being driven, in large part, by changes in the generation mix. As NERC notes in its 2009 Assessment, existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation.[38] NERC has identified approximately 131,000 megawatts of new generation planned for construction over the next ten years, with the largest fuel-type growth in gas-fired and wind generation resources.[39] These shifts in the generation fleet increase the need for new transmission. Additionally, the existing transmission system was not built to accommodate this shifting generation fleet. Of the total miles of bulk power transmission under construction, planned, and in a conceptual stage, NERC estimates that 50 percent will be needed strictly for reliability and an additional 27 percent will be needed to integrate variable and renewable generation across North America.[40]

46. Rather than demonstrating a lack of need for action, as claimed by some commenters, the recent increases in constructed and planned transmission facilities supports issuance of this Final Rule at this time to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions. The increased focus on investment in new transmission projects makes it even more critical to implement these reforms to ensure that the more efficient or cost-effective projects come to fruition. The record in this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.

47. As explained below, each of the individual reforms adopted by the Commission is intended to address specific deficiencies in the Commission's existing transmission planning and cost allocation requirements. Through this package of reforms, the Commission seeks to ensure that each public utility transmission provider will work within its transmission planning region to create a regional transmission plan that identifies transmission facilities needed to meet reliability, economic and Public Policy Requirements, including fair

[33] Large Public Power Council (citing *Edison Electric Institute report, available at http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf*).

[34] Edison Electric Institute at v.

[35] NERC 2010 Assessment at 25; *see also* Brattle Group, Attachment at 4 (noting rapid increase in transmission development, from $2 billion annually in the 1990s to $8 billion annual in 2008 and 2009).

[36] Transforming America's Power Industry at 37, *http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf.*

[37] NERC 2010 Long-Term Reliability Assessment at 25.

[38] NERC 2009 Long-Term Reliability Assessment at 8; *see also supra* P 29 (summarizing current state renewable portfolio standards).

[39] NERC 2010 Long-Term Reliability Assessment at 12.

[40] *Id.* at 24.

consideration of lines proposed by nonincumbents, with cost allocation mechanisms in place to facilitate lines moving from planning to development. Although focused on particular aspects of the Commission's transmission planning and cost allocation requirements, these reforms are integrally related and should be understood as a package that is designed to reform processes and procedures that, if left in place, could result in Commission-jurisdictional services being provided at rates that are unjust and unreasonable and unduly discriminatory or preferential.

48. A number of commenters maintain that the Commission in the Proposed Rule failed to provide adequate evidence to support a finding under section 206 of the FPA that the reforms adopted in this Final Rule are necessary to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Section 313(b) of the FPA makes Commission findings of fact conclusive if they are supported by substantial evidence.[41] When applied in a rulemaking context, ''the substantial evidence test is identical to the familiar arbitrary and capricious standard.'' [42] The Commission thus must show that a ''reasonable mind might accept'' that the evidentiary record here is ''adequate to support a conclusion,'' [43] in this case that this Final Rule is needed ''to correct deficiencies in transmission planning and cost allocation processes,'' as described.[44] In the legal authority sections throughout this Final Rule, the Commission discusses how the cases cited by commenters demonstrate that the Commission has met its burden.

49. Commenters that maintain that the Commission's proposal is not supported by substantial evidence demand that the Commission identify evidence that is far in excess of what a reasonable person would require. We thus disagree with such comments, including Indianapolis Power & Light's, that it is necessary for the Commission to determine what needs to be built, where it needs to be built, and who needs to build it. That is not, and is not required to be, the intent of this rulemaking. This rulemaking reforms processes and is not intended to address such questions. No commenter has contested the need for additional transmission facilities, and numerous examples have been provided here of transmission planning and cost allocation impediments to the development of such facilities. Our intent here is to continue to ensure that public utility transmission providers use just and reasonable transmission planning processes and procedures, as required by Order Nos. 888 and 890, to provide for the needs of their transmission customers. Such planning may require public utility transmission providers—in consultation with stakeholders—to determine what needs to be built, where it needs to be built, and who needs to build it, but the Commission is not making such determinations here.

50. We also reject the characterization of factual examples presented to demonstrate the need for reform as anecdotal evidence. A wide range of concerns have been raised by commenters, and the Commission need not, and should not, wait for systemic problems to undermine transmission planning before it acts. The Commission must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and investment in the right transmission facilities as the industry moves forward to address the many challenges it faces. Transmission planning is a complex process that requires consideration of a broad range of factors and an assessment of their significance over a period that can extend from present out to 20, 30 years or more in the future. In addition, the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing. Given the need to deal with these matters over a long time horizon, it is appropriate and prudent that we act at this time rather than allowing the types of problems described above to continue or to increase. In light of these conditions and as explained below, we find that it is reasonable to take generic action through this rulemaking proceeding.

51. A brief consideration of the two cases that commenters rely on to argue that the Commission has not satisfied the substantial evidence standard helps to demonstrate that the standard has been fully met. In *National Fuel,* the court found that the Commission had not met the substantial evidence standard when it sought to extend its standards of conduct that regulate natural gas pipelines' interactions with their marketing affiliates to their interactions with their non-marketing affiliates. The court noted that it had upheld the standards of conduct as applied to pipelines and their marketing affiliates because the Commission had shown both a theoretical threat that pipelines could grant undue preferences to their marketing affiliates and evidence that such abuse had occurred.[45] In finding that the Commission had not met the substantial evidence standard when seeking to extend the standards of conduct, the court noted that the Commission had not cited a single example of abuse by non-marketing affiliates. It concluded that the Commission relied either on examples of abuse or comments from the rulemaking that simply reiterated a theoretical potential for abuse.[46] The court remanded the matter and noted that if the Commission chose to proceed it could even rely solely on a theoretical threat if it could show how the threat justified the costs that the rules would create.[47]

52. Our action in this Final Rule is entirely consistent with the standards that the court set forth in *National Fuel.* We conclude that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities, and that addressing these issues is necessary to ensure just and reasonable rates. In other words, the problem that the Commission seeks to resolve represents a ''theoretical threat,'' in the words of the *National Fuel* decision, the features of which are discussed throughout the body of this Final Rule in the context of each of the reforms adopted here. This threat is significant enough to justify the requirement imposed by this Final Rule. It is not one that can be addressed adequately or efficiently through the adjudication of individual complaints. The problems that we seek to resolve here stem from the absence of planning processes that take a sufficiently broad view of both the tasks involved and the means of addressing them. Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate planning processes are in place.

53. Stated in another way, in the terminology of *National Fuel,* the remedy we adopt is justified sufficiently by the ''theoretical threat'' identified herein, even without ''record evidence of abuse.'' The actual experiences of problems cited in the record herein provide additional support for our

[41] 16 U.S.C. 825l(b).

[42] *Wisconsin Gas Co.* v. *FERC,* 770 F.2d 1144, 1156 (1985); *see also Associated Gas Distributors* v. *FERC,* 824 F.2d 981 at 1018.

[43] *Dickenson* v. *Zurko,* 527 U.S. 150, 155 (1999).

[44] Proposed Rule, FERC Stats & Regs. ¶ 32,660 at P 1.

[45] *National Fuel,* 468 F.3d 831 at 839.

[46] *Id.* at 841.

[47] *Id.* at 844.

action, but are not necessary to justify the remedy.

54. *Associated Gas Distributors* likewise is distinguishable from this proceeding. In that case, the court reviewed the Commission's rationale in Order No. 436 for industry-wide contract demand adjustment conditions, which permitted pipeline customers to reduce their contract demand by up to 100 percent over a period of five years.[48] The court held that the Commission failed to develop an adequate rationale for authorizing what it characterized as the ''drastic action'' of 100 percent contract demand reduction, and that the reasons the Commission provided ''seem[ed] peripheral to the problem the Commission set out to solve.''[49] The court also found that one of the Commission's arguments while ''highly relevant'' to contract demand reduction, failed to support the broad remedy the Commission adopted.[50] The court explained that it was unclear why an industry-wide solution was necessary to solve a problem that the Commission suggested applied only ''to a limited portion of the industry.''[51]

55. We find that the facts and findings of *Associated Gas Distributors* are in no way comparable to the matters involved in this Final Rule. We disagree with commenters that characterize our reasoning as inadequate or peripheral to the problems that the Commission has identified in this proceeding. To the contrary, the reforms adopted herein are necessary to address those problems and are supported by the reasons set forth in this Final Rule. As discussed herein, the Commission finds that the narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities. There is a close relationship between those problems and the Commission's actions here to identify a minimum set of requirements that must be met to ensure that transmission planning processes and cost allocation methods subject to its jurisdiction result in Commission-jurisdictional services being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

56. We also disagree with commenters that argue that the reforms adopted in this Final Rule will have an impact on industry that is comparable to the impact at issue in *Associated Gas Distributors.* The impact in that case involved the potential losses a gas pipeline could face from 100 percent contract demand reduction by a customer over a period of five years. Such reduction represents the complete elimination of expected revenues from gas sales under a contract. By contrast, compliance with this Final Rule will involve the adoption and implementation of additional processes and procedures. Many public utility transmission providers that are subject to this Final Rule already engage in processes and procedures of this type.

57. We acknowledge that some public utility transmission providers may need to do more than others to achieve compliance with the requirements of this Final Rule. Such differences, however, do not mean that the problems identified herein are ''limited to a portion of the industry,'' in the terms used in *Associated Gas Distributors.* Indeed, acting on a generic basis is necessary for the Commission to identify and implement a minimum set of requirements for transmission planning processes and cost allocation methods, as discussed above.

58. We also disagree with commenters who assert that the Commission is relying on unsubstantiated allegations of discriminatory conduct or that the current Order No. 890 processes have not been in place long enough to justify the reforms proposed herein. The courts have made clear that the Commission need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.[52] In *Associated Gas Distributors,* the court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them and that courts do not insist on empirical data for every proposition upon which the selection depends: ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.''[53] As discussed in this Final Rule, the Commission has received many comments arguing that commenters have experienced unjust and unreasonable, or unduly discriminatory or preferential practices in the transmission planning aspects of the transmission service provided by public utility transmission providers and that the lack of guidance from the Commission has delayed, as well as hindered, transmission projects. We have an obligation under section 206 to remedy these unjust and unreasonable, or unduly discriminatory or preferential rates, terms, and conditions and practices affecting rates.

59. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 890, deficiencies in the requirements of the existing *pro forma* OATT must be remedied to support the more efficient and cost-effective development of transmission facilities used to provide Commission-jurisdictional services. Moreover, action is needed to address the opportunities to engage in undue discrimination by public utility transmission providers. Our actions in this Final Rule are necessary to produce rates, terms and conditions that are just and reasonable. We therefore exercise our broad remedial authority[54] today to ensure that rates are not unjust and unreasonable and to limit the remaining opportunities for undue discrimination.

60. We also disagree with the commenters that claim that any concerns with current transmission planning and cost allocation processes are better dealt with on a case-specific basis rather than through a generic rule. While the concerns discussed above that are driving the need for these reforms may not affect each region of the country equally, we remain concerned that the existing transmission planning and cost allocation requirements of Order No. 890 are inadequate to ensure the development of more efficient and cost-effective transmission. It is well established that the choice between rulemaking and case-by-case adjudication ''lies primarily in the informed discretion of the administrative agency.''[55] It is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry-wide problems facing us.

61. Nevertheless, the Commission recognizes that each transmission planning region has unique characteristics and, therefore, this Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences. The Commission recognizes that many transmission planning regions have or are in the process of taking steps to

[48] *Associated Gas Distributors,* 824 F.2d 981 at 1013.

[49] *Id.* at 1018–19.

[50] *Id.* at 1019.

[51] *Id.* at 1018–19.

[52] *TAPS* v. *FERC,* 225 F.3d 667 at 688; *National Fuel,* 468 F.3d 831.

[53] 824 F.2d 981 at 1008.

[54] *Niagara Mohawk Power Corp.* v. *FPC,* 379 F.2d 153, 159 (DC Cir. 1967).

[55] *SEC* v. *Chenery Corp.,* 332 U.S. 194, 203 (1947). *See also Alaska Power & Telephone Co.,* 98 FERC ¶ 61,092, at 61,277 (2002); *Trailblazer Pipeline Co.,* 79 FERC ¶ 61,274, at 62,183 (1997).

address some of the concerns described in this Final Rule. We encourage those regions to use the objectives and principles discussed in this Final Rule to guide continued development and compel them to abide by the requirements of this Final Rule.

62. The Commission recognizes the scope of these requirements, and to that end the Commission will continue to make its staff available to assist industry regarding compliance matters, as it did after Order No. 890. As stated above, as public utility transmission providers work with their stakeholders to prepare compliance proposals, the Commission encourages frequent dialogue with Commission staff to explore issues that are specific to each transmission planning region. The Commission will monitor progress being made.

D. Use of Terms

63. Before turning to the requirements of this Final Rule, the Commission defines several of the key terms used herein. For purposes of this Final Rule, there is a distinction between a transmission facility in a regional transmission plan and a transmission facility selected in a regional transmission plan for purposes of cost allocation. Transmission facilities selected in a regional transmission plan for purposes of cost allocation are transmission facilities that have been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because they are more efficient or cost-effective solutions to regional transmission needs. Those may include both regional transmission facilities, which are located solely within a single transmission planning region and are determined to be a more efficient or cost-effective solution to a regional transmission need, and interregional transmission facilities, which are located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost-effective solution to a regional transmission need. Such transmission facilities often will not comprise all of the transmission facilities in the regional transmission plan; rather, such transmission facilities may be a subset of the transmission facilities in the regional transmission plan. For example, such transmission facilities do not include a transmission facility in the regional transmission plan but that has not been selected in the manner described above, such as a local transmission facility or a merchant transmission facility. A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.

64. In distinguishing between transmission facilities selected in a regional transmission plan for purposes of cost allocation and other transmission facilities that also may be in the regional transmission plan, we seek to recognize that different regions of the country may have different practices with regard to populating their regional transmission plans. In some regions, transmission facilities not selected for purposes of regional or interregional of cost allocation nonetheless may be in a regional transmission plan for informational purposes, and the presence of such transmission projects in the regional transmission plan does not necessarily indicate an evaluation of whether such transmission facilities are more efficient or cost-effective solutions to a regional transmission need, as is the case for transmission facilities selected in a regional transmission plan for purposes of cost allocation. By focusing in parts of this Final Rule on transmission facilities selected in a regional transmission plan for purposes of cost allocation, we do not intend to disturb regional practices with regard to other transmission facilities that also may be in the regional transmission plan.

65. We also clarify that the requirements of this Final Rule are intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule. The requirements of this Final Rule will apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's filing adopting the transmission planning and cost allocation reforms of the *pro forma* OATT required by this Final Rule. We appreciate that transmission facilities often are subject to continuing evaluation as development schedules and transmission needs change, and that the issuance of this Final Rule is likely to fall in the middle of ongoing planning cycles. Each region is to determine at what point a previously approved project is no longer subject to reevaluation and, as a result, whether it is subject to the requirements of this Final Rule.[56] Our intent here is that this Final Rule not delay current studies being undertaken pursuant to existing regional transmission planning processes or impede progress on implementing existing transmission plans. We direct public utility transmission providers to explain in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule.

66. Finally, nothing in this Final Rule should be read as the Commission granting approval to build a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation.'' For purposes of this Final Rule, the designation of a transmission project as a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' only establishes how the developer may allocate the costs of the facility in Commission-approved rates if such facility is built. Nothing in this Final Rule requires that a facility in a regional transmission plan or selected in a regional transmission plan for purposes of cost allocation be built, nor does it give any entity permission to build a facility. Also, nothing in this Final Rule relieves any developer from having to obtain all approvals required to build such facility.

III. Proposed Reforms: Transmission Planning

67. This section of the Final Rule has three parts: (A) Participation in the regional transmission planning process; (B) nonincumbent transmission developers; and (C) interregional transmission coordination.

A. Regional Transmission Planning Process

68. This part of the Final Rule adopts several reforms to improve regional transmission planning. First, building on the reforms that the Commission adopted in Order No. 890, this Final Rule requires each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and complies with existing Order No. 890 transmission planning principles. Second, this Final Rule adopts reforms under which

[56] We note that existing planning processes already include specific points at which a project will no longer be subject to reevaluation.

transmission needs driven by Public Policy Requirements are considered in local and regional transmission planning processes. By ''local'' transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890. These reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers.[57] This, in turn, will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region. Each of these reforms is discussed more fully below.

69. Part A of section III has four subsections: (1) Need for reform concerning regional transmission planning; (2) legal authority for transmission planning reforms;[58] (3) regional transmission plan and Order No. 890 transmission planning principles; and (4) consideration of transmission needs driven by Public Policy Requirements.

1. Need for Reform Concerning Regional Transmission Planning

a. Commission Proposal

70. In the Proposed Rule, the Commission explained that, since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890's regional participation transmission planning principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. The Commission explained that, to meet that principle, each public utility transmission provider is currently required to coordinate with interconnected systems to: (1) Share system plans to ensure that the plans are simultaneously feasible and otherwise use consistent assumptions and data; and (2) identify system enhancements that could relieve congestion or integrate new resources.[59] The Commission thus did not require development of a transmission plan by each transmission planning region. Moreover, the Commission did not require regional transmission planning activities to comply with the transmission planning principles established in Order No. 890.[60] As such, the Commission proposed to require each public utility transmission provider to participate in a regional transmission planning process that satisfies the existing Order No. 890 transmission planning principles[61] and that produces a regional transmission plan.

71. The Commission also explained that, while it intended Order No. 890's economic planning studies transmission planning principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including transmission facilities to integrate new resources and loads on an aggregated or regional basis,[62] it recognized that its statements with respect to the Order No. 890 economic planning studies transmission planning principle may have contributed to confusion as to whether Public Policy Requirements may be considered in the transmission planning process.[63] The Proposed Rule stated that, when conducting transmission planning to serve native load customers, a prudent public utility transmission provider will not only plan to maintain reliability and consider whether transmission facilities or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant Public Policy Requirements. The Proposed Rule further stated that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers. The Commission also noted that providing for incorporation of Public Policy Requirements in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.[64] The Commission therefore proposed to require each public utility transmission provider to amend its OATT so that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.

b. Comments

72. A number of commenters support the Commission's preliminary determination in the Proposed Rule that there is a need to enhance the regional transmission planning process.[65] In supporting the proposal to implement new regional transmission planning requirements, Pennsylvania PUC argues that the current regional transmission planning process does not lend itself to the sort of open and transparent processes that allow state commissions to fully contribute to the regional transmission planning arena. Iberdrola Renewables states that the proposed reforms would advance the sound development of substantial new renewable energy resources, which it argues is critical to the nation's energy security, economic well-being, and the environment. AWEA states that existing transmission planning processes are too parochial in design and practice, and it suggests that the proposed transmission planning reforms will remedy these deficiencies.

73. However, other commenters argue that there is no need for reform of regional transmission planning requirements, at least on a nationwide basis.[66] Ad Hoc Coalition of Southeastern Utilities and Southern Companies argue that any problems that may exist regarding regional transmission planning are local in nature and the Commission should not undertake comprehensive, generic

[57] As in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. We leave such decisions in the first instance to the judgment of public utility transmission providers, in consultation with stakeholders participating in the regional transmission planning process.

[58] Because the legal authority concerns raised by commenters with regard to our regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together.

[59] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 45 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523).

[60] *See Entergy Services, Inc.,* 124 FERC ¶ 61,268, at P 104 (2008).

[61] These transmission planning principles are: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.

[62] Order No. 890's economic planning studies transmission planning principle requires that stakeholders be given the right to request a defined number of high priority studies annually through the transmission planning process, which are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources or loads on an aggregated or regional basis. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547–48.

[63] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 55–57 & n.76.

[64] *Id.* P 63.

[65] *E.g.,* 26 Public Interest Organizations; AWEA; Atlantic Grid; Clean Line; East Texas Cooperatives; Energy Future Coalition Group; Gaelectric; Iberdrola Renewables; Massachusetts Departments; NextEra; Pennsylvania PUC; Western Grid Group; and Wind Coalition.

[66] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Avista and Puget Sound; Bonneville Power; ColumbiaGrid; Indianapolis Power & Light; Southern Companies; and WestConnect.

reform. They argue that the regional transmission planning concerns expressed in the Proposed Rule are not present in the Southeast. ColumbiaGrid, Bonneville Power, Avista, and Puget Sound argue that regional transmission planning in the Northwest is robust. WestConnect makes a similar point regarding its collaborative planning process. Avista and Puget Sound state that the proposed reforms could threaten the continued viability of ColumbiaGrid's successful collaborative approach to planning because of concerns that some ColumbiaGrid members may not participate in that process if the Proposed Rule's reforms are adopted.

74. Others argue that the Commission should allow existing regional transmission planning processes to mature before taking action.[67] Sacramento Municipal Utility District contends that comprehensive transmission planning currently exists, planning studies are being performed, results are being evaluated, and interested stakeholders are actively engaged and, consequently, the Commission need not and should not take further action. Modesto Irrigation District states that existing regional and interconnectionwide transmission planning processes in the West provide an effective and comprehensive way to determine transmission needs and the transmission projects that efficiently address those needs in a manner that is consistent with the bottom up, stakeholder-driven transmission planning processes found in Order No. 890.[68] In reply, California Transmission Planning Group states that it agrees with commenters in the Western Interconnection that existing regional and interconnectionwide processes should continue to mature. It argues that comments expressing frustration with its planning process are indicative of the need to provide such processes time to mature, noting that its work has matured rapidly in the year since it was formed. Coalition for Fair Transmission Policy states that transmission investment has accelerated in recent years and, as a result, current transmission planning processes are working.

[67] *E.g.,* California Transmission Planning Group; Sacramento Municipal Utility District; and WestConnect.

[68] In describing these comments, we use the terms ''interconnectionwide'' and ''regional'' even though many commenters in the western United States used the term ''regional'' for interconnectionwide and ''subregional'' for regional. However, we will continue to use the terms ''interconnectionwide'' and ''regional'' in this Final Rule to make these comments clearer to readers outside of the West.

75. Others argue that the Proposed Rule would lead to undesirable outcomes. California Transmission Planning Group argues that the Proposed Rule would require it to transform itself from a regional coordinator of transmission studies and planning into a quasi-adjudicatory arbiter of the relative economic merits of specific transmission projects or alternatives and a gatekeeper to cost recovery and ratemaking mechanisms. California Transmission Planning Group also notes the legal constraints on many of its public agency members from assuming certain planning-related responsibilities. NorthWestern Corporation (Montana) does not believe the proposed approach is workable in the unorganized market areas in the West because the transmission provider, not the regional planning entity, has the obligation to the Commission through its tariff.

76. North Carolina Agencies argue that transmission planning must be initiated at the local and regional levels subject to state-level authority and based on the needs of customers who bear the burdens and benefits of the decisions resulting from the planning process. North Carolina Agencies also state that transmission developers who offer transmission projects as an alternative to locally planned solutions must be required to participate in and have their proposals considered as part of the relevant state planning process. Imperial Irrigation District points to potential confusion in the West, and states that it believes that the creation of a new regional transmission planning authority would impede, not hasten, transmission development.

77. However, Multiparty Commenters urge the Commission not to be swayed by arguments that reform of the transmission planning and cost allocation processes are not necessary simply because there has been an increase in transmission investment in the last few years, asserting that more investment does not mean that there is enough transmission being built to satisfy future needs, such as the interconnection of renewable resources. NextEra disagrees with commenters asserting that revising transmission planning procedures would disrupt existing processes under Order No. 890, arguing that those processes should be improved if there is a need to do so, as it would be wasteful to withhold needed reforms to observe how current processes would evolve. Powerex states that, although progress has been made in transmission planning processes since Order No. 890 was issued, more reforms are needed to ensure transparency and a level playing field for all stakeholders. National Grid agrees that the Commission should not wait to exercise its authority to require improvements to transmission planning processes. Twenty-six Public Interest Organizations argue that Southern Companies' claims that the transmission planning deficiencies identified in the Proposed Rule do not pertain to them and that implementation of the Proposed Rule would harm existing processes are unsupported by the facts and may reflect the inability of planning authorities to recognize the limits of their own procedures.

c. Commission Determination

78. We conclude that it is necessary to act under section 206 of the FPA to adopt the regional transmission planning reforms of this Final Rule, as discussed more fully below, to ensure just and reasonable rates and to prevent undue discrimination by public utility transmission providers. Our review of the record, including the comments submitted by numerous entities representing a variety of diverse viewpoints, makes clear to us that reform is necessary at this time. Specifically, we conclude that the existing requirements of Order No. 890 are inadequate to ensure that public utility transmission providers in each transmission planning region, in consultation with stakeholders, identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers. Moreover, the existing requirements of Order No. 890 do not necessarily result in the development of a regional transmission plan that reflects the identification by the transmission planning region of the set of transmission facilities that are more efficient or cost-effective solutions for the transmission planning region.

79. As the Commission explained in the Proposed Rule, when an individual public utility transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission alternatives that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders.[69] Through this process, the public utility transmission provider evaluates the

[69] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

various alternatives available to determine a set of solutions that meet the system's needs more efficiently or cost-effectively than other proposed solutions. At the regional level, the Commission has relied on such processes when evaluating filings to help ensure that the recovery of costs associated with transmission facilities recovered through Commission-jurisdictional rates is just and reasonable.[70]

80. In some transmission planning regions, a similar level of analysis is undertaken by public utility transmission providers at the regional level, resulting in the development of a regional transmission plan that identifies those transmission facilities that are needed to meet the needs of stakeholders in the region. This occurs, for example, in each of the existing RTO and ISO regions, which, we note, serve over two-thirds of the nation's consumers.[71] In other transmission planning regions, however, as permitted by Order No. 890, public utility transmission providers use the regional transmission planning process as a forum to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. We conclude that it is necessary to have an affirmative obligation in these transmission planning regions to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively. Given the potential impact such investments could have on rates for Commission-jurisdictional service, we conclude it is necessary to act at this time to enhance the transmission planning-related requirements imposed in Order No. 890.

81. In the absence of the reforms implemented below, we are concerned that public utility transmission providers may not adequately assess the potential benefits of alternative transmission solutions at the regional level that may meet the needs of a transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. For example, proactive cooperation among public utility transmission providers within a transmission planning region could better identify transmission solutions to more efficiently or cost-effectively meet the reliability needs of public utility transmission providers in the region. Further, regional transmission planning could better identify transmission solutions for reliably and cost-effectively integrating location-constrained renewable energy resources needed to fulfill Public Policy Requirements such as the renewable portfolio standards adopted by many states. Similarly, the development of transmission facilities that span the service territories of multiple public utility transmission providers may obviate the need for transmission facilities identified in multiple local transmission plans while simultaneously reducing congestion across the region. Under the existing requirements of Order No. 890, however, there is no affirmative obligation placed on public utility transmission providers to explore such alternatives in the absence of a stakeholder request to do so. We correct that deficiency in this Final Rule.

82. Based on our review of the record and comments in this proceeding, we also require each public utility transmission provider to amend its OATT to explicitly provide for consideration of transmission needs driven by Public Policy Requirements in both local and regional transmission planning processes. As the Commission noted in the Proposed Rule, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, transmission needs driven by Public Policy Requirements. While transmission planning processes in some regions have evolved to reflect compliance with Public Policy Requirements, our review of the comments indicates that some transmission planning processes do not consider transmission needs driven by Public Policy Requirements.[72] As a result, some regions are struggling with how to adequately address transmission expansion necessary to, for example, comply with renewable portfolio standards. These difficulties are compounded by the fact that planning transmission facilities necessary to meet state resource requirements must be integrated with existing transmission planning processes that are based on metrics or tariff provisions focused on reliability or, in some cases, production cost savings.

83. As the Commission explained in the Proposed Rule, consideration of Public Policy Requirements raises issues similar to those raised in the Commission's discussion in Order No. 890 of the economic planning studies transmission planning principle.[73] When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements.[74] Therefore, we conclude that, to avoid acting in an unduly discriminatory manner against transmission customers that serve other loads, a public utility transmission provider must consider these same transmission needs for all of its transmission customers. Moreover, given that consideration of transmission needs driven by Public Policy Requirements could facilitate the more efficient and cost-effective achievement of those requirements, we conclude the reforms adopted herein are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable.

84. Turning to the commenters opposed to these reforms, we are not persuaded by those who argue that any problems with existing transmission planning are local in nature and that the Commission should not undertake comprehensive, generic reform. As we explain above in the section on the general need for the reforms in this Final Rule, the Commission need not make specific factual findings to promulgate a generic rule to ensure

[70] *See, e.g., Transmission Technology Solutions, LLC, et al.* v. *Cal. Indep. Sys. Operator Corp.,* 135 FERC ¶ 61,077, at P 84 (2011) (rejecting complaint regarding California ISO transmission planning process and stating "we find that CAISO reasonably concluded that PG&E's project is ultimately the most prudent and cost-effective solution. We find that for each of the incumbent and non-incumbent proposed projects, CAISO adequately considered lower cost alternatives, selected economically efficient solutions, accounted for more than just capital costs, and considered additional project benefits.").

[71] *See IRC Brings Value to Reliability and Electricity Markets, available at http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.B00F/About.htm.* As discussed in section V below, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission.

[72] For example, PJM acknowledges in its comments that under its existing transmission planning process, it cannot build transmission to anticipate the development of future generation, including renewable energy resources, that are not associated with specific generator interconnection requests.

[73] In Order No. 890, the Commission intended the economic planning studies principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including facilities to integrate new resources and loads on an aggregated or regional basis. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[74] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 63.

rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[75] As for those commenters that argue that the Commission should allow existing regional transmission planning processes to mature before acting, we believe that the discussion above illustrates that the requirements of the *pro forma* OATT are inadequate to ensure the development of more efficient or cost-effective solutions to regional needs. As we explained in section II above, while transmission planning processes have improved since the issuance of Order No. 890, we are concerned that the existing Order No. 890 requirements regarding transmission planning, as well as cost allocation, are insufficient to ensure that the evolution of transmission planning processes will occur in a manner that ensures that the rates, terms and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential. At the same time, in response to North Carolina Agencies, we do not intend our reforms to preclude the ability of states to actively plan at the local level.

2. Legal Authority for Transmission Planning Reforms[76]

a. Commission Proposal

85. In the Proposed Rule, the Commission explained that the proposed reforms in the areas of regional transmission planning and interregional transmission coordination are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. The Commission also noted that the Proposed Rule builds on Order No. 890, in which the Commission required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process, among other things, in order to remedy opportunities for undue discrimination in the provision of transmission services.[77]

b. Comments

86. Several commenters argue that the Commission has adequate statutory authority to undertake the planning reforms in the Proposed Rule.[78] Iberdrola Renewables contends that the Commission has a firm legal basis to adopt the proposed reforms and has already relied on its authority to require regional transmission planning efforts in Order No. 890. In response to comments arguing that the Proposed Rule oversteps the Commission's authority, Exelon states that the proposed coordination reforms are well within the Commission's statutory authority to remedy the potential for undue discrimination in transmission planning activities, citing FPA sections 205 and 206, as well as *New York* v. *FERC*.[79] ITC Companies' reply comments also argue that the Commission has the legal authority to implement its proposals, citing the Commission's plenary authority over interstate transmission under FPA section 201 and noting that courts have broadly defined transmission in interstate commerce due to the interconnected nature of the transmission grid. Multiparty Commenters agree that the proposed reforms are within the Commission's plenary authority, and they believe that the Proposed Rule properly identifies deficiencies in transmission planning and cost allocation, and that requirements for transmission planning and cost allocation are necessary for fully competitive wholesale markets and thus fall squarely within the Commission's jurisdiction.

87. In response to those asserting that the Commission cannot require interregional agreements to coordinate planning because of section 202(a)'s voluntary coordination language, commenters assert that such arguments are contrary to precedent affirming Order Nos. 888 and 2000. Exelon notes that *Public Utility District No. 1 of Snohomish County* v. *FERC*,[80] which affirmed Order No. 2000, found that mandatory RTO rules did not run afoul of section 202(a). ITC Companies also assert that section 202(a) does not prohibit interregional planning agreements, contrary to some comments. Multiparty Commenters also argue that section 202 does not impose a limitation on the Commission's section 206 jurisdiction. In addition, commenters such as ITC Companies and Multiparty Commenters argue that the proposals do not preempt state jurisdiction over siting decisions. Twenty-six Public Interest Organizations argue that the FPA requires the Commission to address identified transmission planning deficiencies.

88. Some commenters argue that the Commission may consider public policy requirements. Exelon disagrees with those asserting that the Commission cannot require public utility transmission providers to consider the impacts of public policies under federal and state laws and regulations, and argues that the Commission is not establishing an independent obligation to satisfy such public policy requirements. Exelon states that courts have consistently recognized the Commission's need to adjust its regulation under the FPA to meet the changing needs of the industry.[81] LS Power explains that the proposal regarding public policy requirements is not an effort to pursue those goals but rather to ensure that transmission service is offered at just and reasonable rates. EarthJustice argues that, contrary to commenters challenging the Proposed Rule with respect to the consideration of public policy requirements, the Commission did not propose to infringe on state jurisdiction. EarthJustice argues that there is substantial evidence to support the Commission's conclusions in the Proposed Rule.[82]

89. Some commenters, however, assert that the Commission lacks jurisdiction to mandate the transmission planning reforms included in the Proposed Rule.[83] These commenters cite to section 202(a) of the FPA, which provides that coordination and interconnection arrangements are to be left to the voluntary action of public utilities. California ISO points to *Central Iowa Power Coop.* v. *FERC*,[84] which held that, in light of the voluntary nature of coordination under FPA section 202(a), the Commission's authority under FPA section 206 does not include the authority to require modifications to an otherwise just and reasonable tariff or jurisdictional agreement simply because the Commission has concluded that

[75] *See discussion supra* section II.C.

[76] As noted above, because the legal authority concerns raised by commenters with regard to both our regional transmission planning reforms and our interregional transmission coordination reforms are so closely related, we address these concerns together in this section of the Final Rule.

[77] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 1–2.

[78] *E.g.*, Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[79] 535 U.S. 1 (2002).

[80] 272 F.3d 607 (DC Cir. 2001).

[81] Exelon (citing *New York* v. *FERC*, 535 U.S. 1 (2002)), *Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667 (DC Cir. 2000), and *Public Util. Dist. No. 1 of Snohomish Cty* v. *FERC*, 272 F.3d 607 (DC Cir. 2001).

[82] EarthJustice (citing *Louisiana Pub. Serv. Comm'n* v. *FERC*, 551 F.3d 1042, 1045 (DC Cir. 2008)).

[83] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; California ISO; ColumbiaGrid; Nebraska Public Power District; North Carolina Agencies; and Sacramento Municipal Utility District.

[84] 606 F.2d 1156 n. 36 (DC Cir. 1979) (*Central Iowa*).

alternative terms and conditions would better promote the interconnection and coordination of transmission facilities.

90. Several commenters state that the Commission's statutory authority is limited with respect to transmission siting decisions.[85] North Carolina Agencies assert that, with the exception of the Commission's limited backstop authority under FPA section 216, transmission planning and expansion fall strictly within the purview of state regulatory agencies and the Proposed Rule takes into account neither the Commission's lack of authority nor the long-standing authority of the states. Some commenters also explain that the states have authority with respect to integrated resource planning.[86]

91. Several others state that the Commission should confirm that transmission planning, even with the reforms adopted by this Final Rule, continues to be driven by the needs of load-serving entities.[87] Entities such as Ad Hoc Coalition of Southeastern Utilities, APPA, and Nebraska Public Power District point to FPA section 217(b)(4) as the only provision in the FPA that charges the Commission with transmission planning responsibilities, expressing concern that the proposed transmission planning reforms might be read to imply a greater focus on interests of stakeholders other than load-serving entities. National Rural Electric Coops argue that Order No. 890 struck an appropriate balance among interests and should be preserved.[88] APPA argues that the failure to address section 217 makes the Proposed Rule legally deficient. Additionally, several commenters contend the Commission's proposal is inconsistent with section 217, which they state recognizes the primacy of a franchised utility's obligation to do what is needed to fulfill its obligation to service, including the implementation of state-authorized plans for transmission construction.[89]

92. In response, ITC Companies contend that the Proposed Rule is compatible with section 217 regarding the needs of load-serving entities to fulfill their service obligations. They note that section 217 does not mandate the planning of transmission in interstate commerce based on state integrated resource plans or require that the Commission disregard the needs of renewable power producers or other generators.

93. Some commenters argue that the Commission lacks statutory authority to consider broad public policies.[90] Several commenters cite to *NAACP* v. *FPC*[91] for the proposition that the primary purpose of the Commission's statutory mission is to ensure reliable service at just and reasonable rates, and that Congress' direction to the Commission to act in furtherance of the public interest was not a broad license to promote the general welfare. Nebraska Public Power District and Ad Hoc Coalition of Southeastern Utilities add that the Commission has recognized this limitation in addressing its responsibility to consider environmental policy objectives under the National Environmental Policy Act.[92] PSEG Companies argue that the Commission's proposed reforms related to Public Policy Requirements are legally flawed. PSEG Companies state that the Commission's section 206 authority is not unbounded, citing to *California Independent System Operator Corp.* v. *FERC*,[93] where the court held that the Commission was not empowered to remove members of CAISO's board of directors under section 206. Further, PSEG Companies argue that there is no evidence to support the Commission's claims of undue discrimination under section 206.

94. Some commenters state that the Commission has not provided enough reasoning or adequate detail for the Proposed Rule so that parties can comment meaningfully on it, as required by section 553 of the Administrative Procedure Act (APA).[94] The commenters who argue this make three basic claims. They maintain that it is unclear from the Proposed Rule: (1) Whether the Commission proposes that regional and interregional plans will serve as the basis for (a) future orders requiring utilities to undertake construction consistent with the plans or (b) orders compelling utilities to defer to nonincumbent utilities in connection with the construction of transmission facilities needed for reliability purposes; (2) what public policies must be incorporated in transmission plans, or in what manner such policies should be reflected; and (3) what rate mechanism the Commission would employ to allocate costs incurred by nonincumbent transmission providers to entities with whom they have no service or contractual relationship.[95]

95. In addition, Electricity Consumers Resource Council and the Associated Industrial Groups argue that the Proposed Rule may represent a departure from the Commission's regulations under section 35.35(i)(ii), which establishes a rebuttable presumption that ''[a] project that has received construction approval from an appropriate state commission or state siting authority,'' applying the specified criteria, qualifies as being prudently incurred.[96] Southern Companies argue that, because the Proposed Rule did not identify what it would take to satisfy the public policy requirement, the proposal would violate the Due Process Clause's ''fair notice'' requirement.

96. Indianapolis Power & Light questions whether the Commission has satisfied FPA section 206 requirements, arguing that the Commission has not yet found that existing transmission planning (and cost allocation) provisions are unjust and unreasonable and that it has not ''fixed'' the rate or practice that it finds to be unjust and unreasonable.[97]

97. To ensure that any Final Rule will not directly or indirectly require a state or municipality to impair or violate private activity bond rules under section 141 of the Internal Revenue Code, City of Los Angeles Department of Water and Power urges the Commission to include in the Final Rule the following statement: ''All regional and interregional transmission plans and cost allocation methodologies must include a statement that municipal and public power participants are not required to take any action that would violate or impair a private activity bond rule for purposes of section 141 of the Internal Revenue Code of 1986, or any successor statute or regulation.'' Large

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[85] *E.g.*, North Carolina Agencies; Florida PSC; Illinois Commerce Commission; and Nebraska Public Power District.

[86] *E.g.*, Alabama PSC; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Florida PSC; and Commissioner Skop.

[87] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; National Rural Electric Coops; Transmission Access Policy Study Group; and APPA.

[88] Additionally, National Rural Electric Coops request that the Commission to confirm that transmission planning, even with any reforms the Commission adopts in this rulemaking, will continue to be driven in the first instance by the needs of load-serving entities. Transmission Access Policy Study Group makes a similar request.

[89] *E.g.*, Edison Electric Institute; Large Public Power Council; Nebraska Public Power; and Xcel.

[90] *E.g.*, Southern Companies; Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; and Large Public Power Council.

[91] *National Ass'n for the Advancement of Colored People* v. *FPC*, 425 U.S. 662 (1976).

[92] Nebraska Public Power District.

[93] 372 F.3d 395 (DC Cir. 2004) (*CAISO* v. *FERC*).

[94] *E.g.*, Nebraska Public Power District Comments (citing 5 U.S.C. 553, *Florida Power & Light Co.* v. *U.S.*, 846 F.2d 765, 771 (DC Cir. 1988), *Connecticut Light and Power Co.* v. *NRC*, 673 F.2d 525, 530 (DC Cir. 1982)); Large Public Power Council; Salt River Project Comments (citing *United Mine Workers or America* v. *MSHA*, 407 F.3d 1250, 1259 (DC Cir. 2005)).

[95] *E.g.*, Large Public Power Council and Nebraska Public Power District.

[96] 18 CFR 35.35(i)(ii).

[97] Indianapolis Power & Light (citing *Electrical Dist. No. 1* v. *FERC*, 774 F.2d 490, 492–93 (DC Cir. 1985)).

Public Power Council makes a similar comment. In its reply comments, APPA states that City of Los Angeles Department of Water and Power raises a practical and legal issue regarding the participation of public power systems in transmission planning and cost allocation activities, and APPA agrees that the statement suggested by City of Los Angeles Department of Water and Power would foster public power systems' participation in such processes.

98. Nebraska Public Power District states that as long as it participates in regional and interregional transmission planning through the SPP, it is able to commit to enter into regional planning through the SPP tariff, but cannot make such commitments outside of its present RTO membership. Nebraska Public Power District states that it is unclear what commitments may be called for in any transmission planning agreements, such as whether these agreements: (1) Will carry with them specified or unanticipated liability; and/or (2) may include an obligation to defer to regional or interregional transmission plans that could, in Nebraska Public Power District's judgment, interfere with what must be done to remain compliant with state law.

c. Commission Determination

99. We conclude that we have authority under section 206 of the FPA to adopt the reforms on transmission planning in this Final Rule. These reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Moreover, these reforms build on those of Order No. 890, in which the Commission reformed the *pro forma* OATT to, among other things, require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. As we explained in Order No. 890, we found that the existing *pro forma* OATT was insufficient to eliminate opportunities for undue discrimination, including such opportunities in the context of transmission planning.[98] We conclude that the reforms adopted in this Final Rule are necessary to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. We note that no party sought judicial review of the Commission's authority under Order No. 890 to adopt those reforms that we seek to enhance and improve upon here.

100. We disagree that section 202(a) of the FPA precludes us from adopting the transmission planning reforms contained in this Final Rule. Section 202(a) reads, in relevant part, as follows:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * * [99]

Section 202(a) requires that the interconnection and coordination, *i.e.,* the coordinated operation, of facilities be voluntary. That section does not mention planning, and nothing in it can be read as impliedly establishing limits on the Commission's jurisdiction with respect to transmission planning.

101. Transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The transmission planning process itself does not create any obligations to interconnect or operate in a certain way. Thus, when establishing transmission planning process requirements, the Commission is in no way mandating or otherwise impinging upon matters that section 202(a) leaves to the voluntary action of public utility transmission providers. As we discuss herein, section 202(a) refers to the coordinated operation of facilities.

102. Several commenters who argue that section 202(a) prohibits our proposal rely primarily on *Central Iowa* for support.[100] In *Central Iowa,* a party argued that the Commission should have used its authority under section 206 of the FPA to compel greater integration of the utilities in the Mid-Continent Area Power Pool (MAPP) than MAPP members had proposed. In seeking this goal, the party in question sought to have the Commission require MAPP participants ''to construct larger generation units and engage in single system planning with central dispatch.'' [101] The court held that given ''the expressly voluntary nature of coordination under section 202(a),'' the Commission was not authorized to grant that request.[102]

103. The court in *Central Iowa* was thus presented with a request that the Commission require an enhanced level of, or tighter, power pooling. Section 202(a) was relevant to the problem at issue in *Central Iowa* because the operation of the system through power pooling is its central subject matter. We, on the other hand, are focused in this proceeding on the transmission planning process, which is distinct from any specific system operations. Nothing in this Final Rule is tied to the characteristics of any specific form of system operations, and nothing in it requires any changes in the way existing operations are conducted. This Final Rule simply requires compliance with certain general principles within the transmission planning process regardless of the nature of the operations to which that process is attached. The court's interpretation of section 202(a) with respect to system operations is therefore irrelevant here.

104. Commenters point to dicta in *Central Iowa* based on section 202(a)'s legislative history that, they state, suggests that Congress intended that any coordination by public utilities with respect to transmission planning be voluntary. *Central Iowa* cites to, but does not quote directly, the legislative history to support the conclusion that ''Congress was convinced that 'enlightened self-interest' would lead utilities to engage voluntarily in power planning arrangements, and it was not willing to mandate that they do so.'' [103] The language from the legislative history is as follows:

> The committee is confident that enlightened self-interest will lead the utilities to cooperate with the commission and with each other in bringing about the economies which can alone be secured through the planned coordination which has long been advocated by the most able and progressive thinkers on this subject.[104]

105. In response, we note that section 202(a) does not mention the transmission planning process, and nothing in that section causes one to conclude that it was intended to address the transmission planning process that is the subject of this proceeding. There is thus no basis to resort to legislative

[98] *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 422.

[99] 16 U.S.C. 824(a).

[100] *E.g.,* ColumbiaGrid; Sacramento Municipal Utility District; and California ISO.

[101] *Central Iowa,* 606 F. 2d 1156 at 1166.

[102] *Id.* at 1168.

[103] *Id.*

[104] *See Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973) (citing S.Rep. No. 621, 74th Cong., 1st Sess. 49).

history for further clarification.[105] Moreover, even if resorting to legislative history was appropriate in this context, we note that this passage from the legislative history also does not refer to the transmission planning process that is the subject of this Final Rule. Instead, the legislative history refers to ''planned coordination,'' *i.e.,* to the pooling arrangements and other aspects of system operation that are the underlying focus of section 202(a). It is in this sense that *Central Iowa* must be understood when it refers to engaging ''voluntarily in power planning arrangements.'' The ''planned coordination'' mentioned in the legislative history cited in *Central Iowa* means ''planned coordination'' of the operation of facilities, not the planning process for the identification of transmission facilities. In short, neither *Central Iowa* nor the legislative history cited in that case involves or applies to the planning process for transmission facilities. Rather they deal with the coordinated, *i.e.,* shared or pooled, operation of facilities after those facilities are identified and developed. By contrast, this Final Rule deals with the planning process for transmission facilities, a separate and distinct set of activities that occur before the operational activities that are the underlying focus of section 202(a).

106. Similarly, section 202(a) has no bearing on whether the Commission can mandate requirements on regional and interregional cost allocation. The cost allocation requirements of this Final Rule do not mandate that any entity engage in any interconnection or coordination of facilities in contravention of the requirement in section 202(a) that these matters be left to the voluntary decisions of the entities in question. Section 202(a) does not address matters involved in cost allocation.

107. We acknowledge that there is longstanding state authority over certain matters that are relevant to transmission planning and expansion, such as matters relevant to siting, permitting, and construction. However, nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule, like those of Order No. 890, are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs. In establishing these reforms, the Commission is simply requiring that certain processes be instituted. This in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities. For this reason, we see no reason why this Final Rule should create conflicts between state and federal requirements.

108. We disagree with the commenters who argue that this Final Rule is inconsistent with or precluded by, or legally deficient for failing to rely on, section 217 of the FPA.[106] Our approach in this Final Rule is to build on the requirements of Order No. 890 of ensuring open and transparent transmission planning processes to evaluate proposed transmission projects, a goal that does not conflict with FPA section 217. Indeed, we believe that this Final Rule is consistent with section 217 because it supports the development of needed transmission facilities, which ultimately benefits load-serving entities. The fact that this Final Rule serves the interests of other stakeholders as well does not place it in conflict with section 217. We thus cannot agree with Ad Hoc Coalition of Southeastern Utilities that we should ensure that our transmission planning and cost allocation reforms give systematic preference to any particular set of interests. Section 217 does not require this result. It only requires that we use our authority in a way that facilitates planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. We have indicated that we will follow a flexible approach that accommodates the needs and characteristics of particular regions, and we are confident that this approach can address the needs of load-serving entities in the Southeast and elsewhere.

109. We also disagree with commenters who argue that we lack jurisdiction to require the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process. In requiring the consideration of transmission needs driven by Public Policy Requirements, the Commission is not mandating fulfillment of those requirements. Instead, the Commission is acknowledging that the requirements in question are facts that may affect the need for transmission services and these needs must be considered for that reason. Such requirements may modify the need for and configuration of prospective transmission facility development and construction. The transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.

110. Our disagreement with commenters on this point can be best explained by considering the case that they use to support their arguments, *NAACP* v. *FPC.* In that case, the Court found that the Commission did not have power under the FPA or the Natural Gas Act (NGA) to construe its obligation to promote the public interest under those statutes as creating ''a broad license to promote general public welfare.'' [107] Specifically, the Court found that the Commission's duty to promote the public interest under the FPA and NGA ''is not a directive to the Commission to seek to eradicate discrimination,'' and it thus did not authorize the Commission to promulgate rules prohibiting the companies it regulates from engaging in discriminatory employment practices merely because the statutes pertain to matters affected with a public interest.[108] The Commission is doing nothing analogous when specifying that transmission needs driven by Public Policy Requirements be taken into account in the transmission planning process.

111. Requiring the development of a regional transmission plan that considers transmission needs driven by Public Policy Requirements cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA. Public Policy Requirements can directly affect the need for interstate transmission facilities, which are squarely within the Commission's jurisdiction. Moreover, we are not specifying the Public Policy Requirements that must be considered in individual local and regional transmission planning processes.[109] This further confirms that, in requiring that the transmission planning process

[105] *See, e.g., Connecticut Nat'l Bank* v. *Germain,* 503 U.S. 249, 253–54 (1992) (''[I]n interpreting a statute a court should always turn first to one, cardinal canon before all others. We have stated time and again that courts must presume that a legislature says in a statute what it means and means in a statute what it says there.'' (citations omitted)).

[106] Section 217(b)(4) of the FPA specifies that: ''The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'' 16 U.S.C. 824q(b)(4).

[107] *NAACP* v. *FERC,* 425 U.S. 662 at 668.

[108] *Id.* at 670.

[109] *See infra* section III.A.4.

include the evaluation of potential solutions to identified transmission needs driven by Public Policy Requirements, the Commission is simply requiring the consideration of facts that are relevant to the transmission planning process. In doing so, it is neither pursuing nor enforcing any specific policy goals.

112. Other commenters cite *CAISO* v. *FERC* for the proposition that the Proposed Rule extends beyond our authority under the FPA. In that case, the court found that the Commission did not have authority under section 206 of the FPA to direct the California ISO to alter the structure of its corporate governance, concluding that the choosing and appointment of corporate directors is not a ''practice * * * affecting [a] rate'' within the meaning of the statute.[110] The court explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.'' [111] Unlike the corporate governance matters at issue in that proceeding, the transmission planning activities that are the subject of this Final Rule have a direct and discernable affect on rates. It is through the transmission planning process that public utility transmission providers determine which transmission facilities will more efficiently or cost-effectively meet the needs of the region, the development of which directly impacts the rates, terms and conditions of jurisdictional service. The rules governing the transmission planning process are therefore squarely within our jurisdiction, whether the particular transmission facilities in question are planned to meet reliability needs, address economic considerations, or meet transmission needs driven by a Public Policy Requirement.

113. We disagree with the commenters who argue that the Proposed Rule does not comply with the APA because the Proposed Rule does not provide enough reasoning or adequate detail to permit parties to comment meaningfully on it. Section 553(b)(3) of the APA requires that a notice of proposed rulemaking contain ''either the terms or substance of the proposed rule or a description of the subjects and issues involved.'' [112] The purpose of the requirement is to ensure that ''persons are 'sufficiently alerted to likely alternatives' so that they know whether their interests are 'at stake.' '' [113] Courts have held in this connection that a ''[n]otice of proposed rulemaking must be sufficient to fairly apprise interested parties of the issue involved * * *, but it need not specify every precise proposal which [the agency] may ultimately adopt as a rule.'' [114] We disagree with commenters arguing that this requires us to identify the issues that might be raised in future orders by the Commission should disputes arise as to the construction of transmission facilities in the regional transmission planning process. This Final Rule is focused on ensuring that there is a fair regional transmission planning *process,* not substantive outcomes of that process.

114. We disagree with Southern Companies' argument that the Proposed Rule violated the fair notice requirement of the Due Process Clause because it did not identify how the Public Policy Requirements in the transmission planning process would be satisfied. As explained above, fair notice requires that we apprise parties of the issues involved. In this respect, all interested parties have had fair notice and an opportunity to comment on the Commission's proposed requirement regarding the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process and to provide their perspectives, consistent with the notice and comment requirements of the APA. Moreover, the case that Southern Companies cite in support of their argument, *Trinity Broadcasting of Fla., Inc.* v. *FCC,*[115] is not on point. That case involved a denial by the Federal Communications Commission (FCC) of an application to renew a commercial television broadcast license that could have been renewed under a statutory preference in favor of minority-controlled firms. A majority of the applicant's board was made up of members of minority groups, but the FCC denied the application because the applicant had not satisfied its interpretation of minority control as *de facto* or ''actual'' control of operations. The court found that the agency had not given sufficient notice of its interpretation of minority control to justify punishment in the form of denial of the application. Nothing analogous is occurring here. *Trinity Broadcasting* did not involve a rulemaking proceeding, as is the case here, but rather an adjudication that raised the issue of ''[w]hat constitutes sufficiently fair notice of an agency's interpretation of a regulation to justify punishing someone for violating it?'' [116] A rulemaking such as the present proceeding does not involve the assessment of penalties for failure to comply with a particular regulation, and therefore the notice that is required before penalties can be assessed has no relevance here.

115. We also disagree that this Final Rule may represent a departure from section 35.35(i)(ii) of the Commission's regulations, which establishes a rebuttable presumption that a transmission project that has received construction approvals from relevant state regulatory agencies satisfies Order No. 679's [117] requirement that the transmission project is needed to ensure reliability or reduce the cost of delivered power by reducing congestion. The rebuttable presumption of prudent investment provided for in section 35.35(i)(ii) applies only to Commission determinations with respect to incentive-based rate treatments for investment in transmission infrastructure. The Proposed Rule does not ''represent a departure'' from this provision because the provision deals with matters that are not covered or affected by the Proposed Rule. Electricity Consumers Resource Council and Associated Industrial Groups therefore have not adequately explained why they believe the Proposed Rule represented such a departure.

116. With respect to Indianapolis Power & Light's assertion that the Commission has failed to satisfy FPA section 206, we conclude that we have met section 206's burden. Our review of the record demonstrates that existing transmission planning processes are unjust and unreasonable or unduly discriminatory or preferential. Specifically, we conclude that the record shows that, for the *pro forma* OATT (and, consequently, public utility transmission providers' OATTs) to be just and reasonable and not unduly discriminatory or preferential, it must be revised in the context of transmission planning to include the requirement that regional transmission planning processes result in the production of a regional transmission plan using a process that satisfies the specified Order No. 890 transmission planning

[110] *CAISO* v. *FERC,* 372 F.3d 395 at 403.

[111] *Id.*

[112] 5 U.S.C. 553(b)(3).

[113] *Spartan Radiocasting Co.,* v. *FCC,* 619 F.2d 314, 321 (4th Cir. 1980) (citing *South Terminal Corp.* v. *EPA,* 504 F.2d 646, 659 (1st Cir. 1974)).

[114] *Id.* 321–22 (citing *Consolidation Coal Co.* v. *Costle,* 604 F.2d 239, 248 (4th Cir. 1979)).

[115] 211 F.3d 618, 628 (DC Cir. 2000) (*Trinity Broadcasting*).

[116] *Trinity Broadcasting,* 211 F.3d 618 at 619.

[117] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g,* Order No. 679–A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g,* 119 FERC ¶ 61,062 (2007).

principles and that provides an opportunity to consider transmission needs driven by Public Policy Requirements. We conclude that these reforms satisfy the section 206 standard because they help ensure just and reasonable rates and remove those remaining opportunities for undue discrimination.

117. Finally, with respect to the concerns raised by City of Los Angeles Department of Water and Power, APPA, Nebraska Public Power District, and others regarding the legal issues associated with public power participation in the regional transmission planning processes, we make the following observations. First, as discussed in the section of this Final Rule addressing reciprocity, we reiterate that this Final Rule simply applies the reciprocity principles set forth in Order Nos. 888 and 890 regarding non-public utility transmission provider participation in transmission planning processes. Second, non-jurisdictional entities, unlike public utilities, may choose whether to join a regional transmission planning process and, to the extent they choose to do so, they may advocate for those processes to accommodate their unique limitations and requirements.

3. Regional Transmission Planning Principles

a. Commission Proposal

118. The Proposed Rule would require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that meets the following transmission planning principles: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies. This proposal did not include two of the Order No. 890 transmission planning principles, namely the cost allocation transmission planning principle and the regional participation transmission planning principle. More specifically, the Commission would require that each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that more efficiently or cost-effectively meet the needs of public utility transmission providers, their customers and other stakeholders.[118]

119. The Proposed Rule also would provide that a merchant transmission developer that does not seek to use the regional cost allocation process would not be required to participate in the regional transmission planning process, although such a developer would be required to comply with all reliability requirements applicable to transmission facilities in the transmission planning region in which its transmission project would be located.[119] To reiterate, merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates. The Proposed Rule states that such a merchant transmission developer would not be prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.[120]

b. Comments

120. Many commenters agree that the Commission should require public utility transmission providers to produce a regional transmission plan using a process that complies with the Order No. 890 transmission planning principles.[121] NextEra supports the Commission's proposal provided that a regional transmission planning process produces a regional transmission plan with identified transmission facilities to be built in the near-term. Iberdrola Renewables contends that the current piecemeal, generation-driven approach to transmission development is inefficient and ineffective and hinders development of renewable energy resources. Duke states that it supports the requirement that a regional transmission plan be produced through a regional transmission planning process. Maine PUC believes that in New England, the distinction between different types of transmission projects (*i.e.,* reliability and market efficiency transmission facilities) has impeded the development of transmission facilities that would reduce congestion costs and provide greater access to low-cost supply, including renewable resources, and suggests that the Commission consider eliminating this distinction.

121. Most commenters addressing the proposed transmission planning reforms support the Commission's proposal to require public utility transmission providers to adopt several of the Order No. 890 transmission planning principles for the regional transmission planning process.[122] Some commenters ask the Commission to clarify that the existing Order No. 890 transmission planning principles would remain applicable to regional transmission planning processes.[123] Some commenters also seek clarification that individual transmission owners must comply with Order No. 890 transmission planning principles and have an OATT Attachment K on file with the Commission.[124] Transmission Dependent Utility Systems state that transmission owners must comply with Order No. 890 transmission planning principles even if they are planning local transmission projects in an RTO.

122. Several supporting the Proposed Rule stress that fair process, transparency, and robust stakeholder participation are important components of the transmission planning process.[125] PPL Companies state that all interested parties, especially those that may be allocated costs for a particular transmission project, should have an opportunity to provide meaningful input into the regional transmission planning process, and urge the Commission to require that historical and real-time data be made available to interested stakeholders. Transmission Dependent Utility Systems contend that transmission customers need to play an integral role in the regional transmission planning process. 26 Public Interest Organizations, Green Energy and 21st Century, and Western Independent Transmission Group state that transparency in transmission planning and access to models and data are critical to nonincumbent resources and grid infrastructure providers if these entities are to be effective participants in regional transmission plan development. Independent Energy Producers Association urges the Commission to emphasize that the

[118] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 51.

[119] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

[120] *Id.* P 99.

[121] *E.g.,* Anabaric and PowerBridge; AWEA; City and County of San Francisco; DC Energy; Duke; Duquesne Light Company; East Texas Cooperatives; Energy Future Coalition Group; LS Power; MISO; National Grid; NEPOOL; New England States' Committee on Electricity; New England Transmission Owners; NextEra; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Wilderness Society and Western Resource Advocates; and Wisconsin Electric Power Company.

[122] *E.g.,* ISO New England and SPP.

[123] *E.g.,* East Texas Cooperatives and Champlain Hudson.

[124] *E.g.,* Transmission Dependent Utility Systems and Old Dominion.

[125] *E.g.,* PPL Companies; DC Energy; Direct Energy; 26 Public Interest Organizations; Green Energy and 21st Century; Western Independent Transmission Group; City of Santa Clara; Natural Resources Defense Council; New Jersey Division of Rate Counsel; and Iberdola Renewables.

openness, transparency, and inclusiveness criteria of Order No. 890 should apply to all phases of the transmission planning process. New Jersey Board suggests that transmission providers be required to state the baseline methodology on which load forecasts are based. However, Anbaric and PowerBridge suggest consideration of internal procedures to treat transmission project information as confidential, including protections to ensure that transmission projects that are not selected in the regional transmission plan will remain confidential.

123. Some commenters also address dispute resolution issues in the regional transmission planning process. City of Santa Clara believes that transmission planning processes should include an effective and meaningful dispute resolution process, including the ability to request Commission resolution of unresolved disputes. Transmission Access Policy Study Group argues that guidance from the Commission is needed to ensure that the dispute resolution process is useful, suggesting that use of reasonable, nondiscriminatory criteria to minimize the potential for discriminatory results, particularly with regard to the inclusion or exclusion of project proposals in a regional transmission plan and the consideration of public policy objectives in the transmission planning process. Transmission Access Policy Study Group suggests that the Commission establish a backstop dispute resolution or expedited complaint process to have a forum for addressing disputes regarding transmission projects selected or not selected in regional transmission plans.

124. Some commenters recommend that the Commission continue to recognize regional flexibility with respect to transmission planning processes.[126] Kansas City Power & Light and KCP&L Greater Missouri supports the Proposed Rule's suggestion that the Commission would defer to each region to develop transmission planning processes that address regional needs, noting that each region has developed differently and that not all regions are at the same level of maturity. Northern Tier Transmission Group states that the Commission should provide flexibility as to the manner in which regional plans are produced, emphasize expected results rather than process, and clarify that the region may continue to rely on a ''bottom-up'' process in developing the plan. SPP recommends that transmission planning authorities be permitted to develop, through their stakeholder processes and in consultation with state regulatory commissions, strategies and metrics to achieve region-appropriate compliance with the Final Rule.

125. Many entities that support the Proposed Rule believe that the regional transmission planning process in which they participate already satisfies the proposed requirements.[127] ISO/RTO Council asks that the Final Rule reflect that ISOs and RTOs already satisfy the requirements and that no further demonstration or tariff language be required in a future compliance filing with the exception of any new or altered requirements imposed by the Final Rule. In response, 26 Public Interest Organizations agree that the proposed reforms should not modify or interfere with progress being made by transmission planners with transmission planning processes that comply with or exceed Order No. 890 requirements and that only those tariff provisions that are affected by the Final Rule need to be filed.

126. On the other hand, Iberdrola Renewables states that the Commission should make clear that reliance on existing institutions and approaches would be adequate only if they can effectively implement the Commission's goals of driving needed transmission infrastructure investment. To that end, it states that in areas not covered by RTOs or ISOs, new regional agreements would be needed to ensure that the transmission providers in the region have a governance structure for undertaking the regional and interregional transmission planning obligations and a workable mechanism for sharing costs consistent with the cost allocation guidelines, and clarify the factors it would consider in determining whether a particular regional proposal or compliance filing has sufficiently broad regional support to merit any deference.

127. Some commenters ask the Commission to clarify the term ''transmission planning region'' as it relates to the requirements of the Proposed Rule.[128] Indianapolis Power & Light and Powerex ask the Commission to define ''region'' in a Final Rule and include a definition of transmission planning region in whatever regulations are promulgated. California Municipal Utilities state that they believe regional consolidation of transmission planning regions should not be forced and that more detail is needed from the Commission for its members to determine if current transmission planning processes meet the requirements of the Proposed Rule. Solar Energy Industries and Large-scale Solar contend that the Commission should ensure that, on the review of compliance filings, the scope of the self-selected planning regions does not create inadvertent planning seams that inhibit the development of transmission projects needed to meet public policy requirements established by state or federal laws or regulations.

128. Several commenters urge the Commission to clarify that existing ISOs and RTOs are considered regions for purposes of transmission planning.[129] However, ITC Companies state that RTO boundaries are not always the right ones for transmission planning, and ITC Companies are concerned that, given the focus of RTOs on developing and running energy markets, it might be difficult for RTOs to plan transmission from a truly independent perspective. Instead, ITC Companies suggest that the planning function be split off from the market function so that there is a truly independent planning authority. In reply, California ISO argues that ITC Companies' recommendation is tantamount to mandating the creation of new entities, which it argues the Commission cannot do. AWEA asks the Commission to clarify that more than one organized market could form a single region for transmission planning and cost allocation purposes.

129. Commenters express different views on defining transmission planning regions outside of the ISO and RTO context. MISO Transmission Owners suggest that, where ISOs or RTOs do not exist, the Commission should allow each transmission provider to propose its own definition of what it considers its transmission planning region. Further, they state that the Commission should not define the term ''transmission planning region'' to be any larger or broader than an RTO or ISO region. MISO states that public utility transmission providers not associated with existing RTOs should either be required to form transmission regional planning areas with each other

[126] *E.g.,* Kansas City Power & Light and KCP&L Greater Missouri; Edison Electric Institute; and WIRES.

[127] *E.g.,* Bonneville Power; Duke; Massachusetts Departments; California ISO; Sunflower and Mid-Kansas; MISO Transmission Owners; California Commissions; MISO; New England States' Committee on Electricity; Indianapolis Power & Light; Northeast Utilities; ISO New England; New York ISO; Southern Companies; and Long Island Power Authority.

[128] *E.g.,* NextEra; Clean Line; California Municipal Utilities; American Transmission; and Arizona Corporation Commission.

[129] *E.g.,* ISO/RTO Council; California ISO; MISO Transmission Owners; Indianapolis Power & Light; and NextEra.

or participate in regional transmission planning with an adjacent RTO. Some commenters ask the Commission to determine that, in non-RTO regions, a single transmission provider or utility family cannot serve as a transmission planning region.[130] Transmission Access Policy Study Group urges the Commission to specify that transmission planning regions in areas outside of RTOs include at least two transmission providers and be at least as large as the smaller of a state or one of NERC's Regional Entities. NextEra suggests that, in non-RTO areas, geographic scope should be determined by factors such as the level of interconnections between utilities, power flows, boundaries of existing NERC regions, and historical coordination practices.

130. Ad Hoc Coalition of Southeastern Utilities claim that the Proposed Rule makes several incorrect statements concerning what constitutes a region for transmission planning purposes in the Southeast.[131] They note that the Proposed Rule references both regional and interregional organizations and processes (including NERC regional entities) as being regional for purposes of the Proposed Rule and assert that a holding that only RTO regions are sufficiently encompassing to meet the proposed requirements would be arbitrary and capricious. Given that the Commission has previously recognized that the South Carolina Regional Transmission Planning (SCRTP) process complies with Order No. 890, and as such is a ''regional transmission planning process,'' South Carolina Electric & Gas asks the Commission to clarify that the SCRTP constitutes a ''regional transmission planning process'' as contemplated by the Proposed Rule. Colorado Independent Energy Association supports the designation of WestConnect as a regional transmission planning organization for the purposes of transmission planning and development in Colorado and to make findings to that effect in this Final Rule. Florida PSC and Commissioner Skop argue that if the Commission adopts a definition of ''region'' that does not recognize Florida as a distinct transmission planning region, and Florida becomes part of a multistate region, then it is unclear what role the Florida PSC would retain, if any, over the transmission planning and cost allocation processes in Florida.[132]

131. Many commenters recommend that transmission providers should evaluate both transmission and non-transmission solutions during the regional transmission planning process.[133] 26 Public Interest Organizations and Dayton Power and Light assert that consideration of non-transmission solutions with all other resource options is needed to determine the most cost-effective way to meet grid needs. 26 Public Interest Organizations ask the Commission to establish minimum requirements for: what types of resources should be assessed; how assessments should be conducted; and what types of modeling and sensitivity analyses are needed to estimate and compare the costs and benefits of option, implementation timelines, and relative risks of various resource choices. New Jersey Board believes that transmission providers should provide peak load reduction data that demonstrate the effect of demand response and energy efficiency on baseline forecasts. MISO supports the consideration of non-traditional solutions so long as this process does not interfere with state authority over integrated resource planning. Western Grid Group and Pattern Transmission suggest that resource planning and transmission planning should be reintegrated.

132. On the other hand, Ad Hoc Coalition of Southeastern Utilities states that a requirement for regional transmission planning processes to consider both transmission and non-transmission solutions is inconsistent with transmission planning procedures in the Southeast. It explains that non-transmission solutions are typically considered in integrated resource planning and request for proposal processes during the current ''bottom-up'' transmission planning process. It states that including a generation resource as an alternative during the regional transmission planning process would convey a right of generation planning to the Commission that would be inconsistent with state law. Accordingly, it states that there are no transmission planning gaps in the Southeast that the Commission needs to address. In its reply comments, Ad Hoc Coalition of Southeastern Utilities argues that such a policy would be inappropriate because there would be winners and losers in any given state, such a ''top-down'' process would risk losing the emphasis on consumers that currently exists in the state-regulated processes. Ad Hoc Coalition of Southeastern Utilities, in responding to comments by Western Grid Group and Pattern Transmission, argues that transmission planning and resource planning in the Southeast have not diverged and that further reforms are unnecessary. Southern Companies agree.

133. MISO Transmission Owners ask the Commission to provide additional guidance regarding the meaning of ''non-transmission solutions'' and which of these solutions transmission providers are required to include in their transmission planning processes. MISO Transmission Owners state that if non-traditional solutions must be considered, then the Commission should clarify that they are required to participate in the transmission planning process on a similar basis as transmission projects.

134. Other commenters ask for clarification and guidance from the Commission on other transmission planning-related issues associated with the Proposed Rule. WIRES believes that the Commission should consider additional rules that promote consistent transmission planning cycles, stakeholder procedures, action timelines, and criteria for evaluating project proposals. Transmission Access Policy Study Group also suggests that the Commission require regular updating of regional transmission plans, and require jurisdictional transmission providers to file, for public comment, a ''planning report card'' identifying the projects proposed during the transmission planning process, the projects approved and included in the regional transmission plan, and the projects that were proposed but excluded from the plan and the reasons those proposed projects were rejected. Transmission Access Policy Study Group states that the Final Rule should subject decisions as to which facilities are included in a regional transmission plan to justification and objective evaluation to prevent discrimination and unjust and unreasonable rates.

135. AEP asserts that a significant flaw in typical transmission planning processes is the failure to consider benefits beyond the near-term.

[130] *E.g.,* AWEA; Clean Line; G&T Cooperatives; Integrys; and NextEra.

[131] In reply comments, South Carolina Office of Regulatory Staff state that it concurs with Ad Hoc Coalition of Southeastern Utilities' views regarding the uniqueness of transmission planning in the Southeast.

[132] Additionally, Florida PSC and Commissioner Skop express concern about the lack of Florida-based commenters, noting that either Florida utilities joined a broader coalition of commenters or, as in the case of NextEra, did not comment from the perspective of its Florida-based utility. Florida PSC and Commissioner Skop ask the Commission to take the lack of Florida-specific points of view into account when it considers its proposals.

[133] *E.g.,* AWEA; California Commissions; Wisconsin Electric; Omaha Public Power District; Dayton Power and Light; Eastern Environmental Law Center; Environmental NGOs; NRG; Vermont Electric; EarthJustice; and SPP.

Therefore, AEP recommends that the Commission direct each transmission planning region to develop a long-term plan that utilizes a 20–30 year planning horizon in the determination of need analysis (while still permitting RTOs to annually evaluate shorter-term projects needed to complement the long-term plan). AEP argues that the useful life of any transmission facility is likely to exceed 40 years and, consequently, the most efficient transmission planning process should cover a minimum span of 20 years, and cites to SPP's and California ISO's transmission planning processes, which use 20-year planning horizons.

136. Primary Power supports the concept that every transmission provider must participate in a regional transmission planning process where specific projects are determined to be in the public convenience and necessity, and urges the Commission to devise threshold requirements ensuring that transmission planners have a degree of independence from market participants that would promote equitable and economically supportable results in terms of which transmission facilities are built and who ultimately pays for them. Some commenters also ask the Commission to clarify that least-cost planning is a driver of the transmission planning process. Transmission Dependent Utility Systems state that both the regional and interregional transmission planning processes adopted by the Final Rule should include clarification that coordination of reliability and economic transmission planning includes identifying optimal solutions to congestion for all transmission customers and load-serving entities across the region. Transmission Dependent Utility Systems recommend that the Commission clarify this concept in the Final Rule and explicitly recognize a joint optimization requirement.

137. Solar Energy Industries and Large-scale Solar suggest that the Commission require holistic long-term planning on a regional basis, in which the interaction of proposed projects with other projects across the region, as well as the integration of renewable resources, distributed generation, and demand response is considered. Transmission Agency of Northern California asks the Commission to clarify that a regional transmission planning ''process'' need not be narrowly defined as participation in a single set of procedures and that the transmission planning process need not serve every planning purpose. Arizona Corporation Commission seeks clarification on who would determine whether a transmission project is a reliability project within the context of the regional transmission planning process. Arizona Corporation Commission suggests that state-level entities, such as state utility commissions, should continue to determine whether a transmission project is a reliability project during line siting and/or determination of need proceedings. Additionally, it states that all proposed transmission projects should be freshly evaluated in each transmission planning cycle so that projects are aligned with transmission needs at the time and adequately incorporate current public policy requirements.

138. Some commenters seek assurance from the Commission that the needs of states and load-serving entities would be considered in the regional transmission planning process. NARUC states that the Final Rule should identify the states as key players in any transmission planning process, pointing to the primary role of states in transmission siting. E.ON emphasizes that the Commission should work to ensure that the Final Rule's planning requirements not give rise to new impediments to a local transmission owning utility's ability to efficiently satisfy customer needs under state service obligations. E.ON suggests that the Commission incorporate the following requirements in its Final Rule: regional and interregional transmission planning processes should be sufficiently flexible to accommodate the real-time requirements of a transmission owner and operator's native load customers; and the transmission planning process should recognize that the obligation to serve still exists in a number of jurisdictions and that any regional plan or process needs to allow for the fact that it is that obligation that drives transmission planning.

139. Others are concerned about the applicability of the Proposed Rule to currently pending transmission projects. Atlantic Wind Connection seeks clarification that sponsored projects with a pending request for inclusion in a regional transmission plan should be studied under the requirements of the Final Rule without undue delay, including delays resulting from any proposed procedural requirements. Edison Electric Institute argues that the Final Rule should apply to projects only on a going-forward basis, and a project identified in an existing plan should not be subject to bumping in a revised transmission planning process filed in compliance with a Final Rule. Northeast Utilities states that the Final Rule should avoid harming projects already included in the transmission planning process.

140. Some commenters ask the Commission to establish a funding mechanism to allow interested parties that are not market participants to fully participate in the regional transmission planning process. twenty-six Public Interest Organizations assert that an essential element of robust and broadly supported regional planning is the participation of non-market participants and that this requires ongoing provider assistance. They state that, because non-market stakeholders have neither the financial resources nor staff expertise to participate effectively in regional transmission plan development processes without special assistance, the Commission should direct transmission providers to facilitate participation of these stakeholders through a funding mechanism to cover reasonable technical assistance and other participation costs. They conclude that these costs can be rolled into the rates of the transmission service providers. Western Grid Group offers suggestions as to how a funding mechanism could be implemented. Additionally, EarthJustice and Environmental Groups urge the Commission to encourage meaningful public participation in the regional transmission planning process, arguing that non-market participation is vital to achieving just, reasonable, and non-discriminatory system plans, and explaining that substantial financial assistance is necessary to assure such meaningful participation.

141. Some commenters, such as AWEA and Transmission Access Policy Study Group, support a requirement that there be an obligation to construct projects identified in regional transmission plans. AWEA recognizes that, while regional and interregional cost allocation arrangements may alleviate some of the impediments to building transmission facilities, an obligation to build projects identified in the regional transmission plan in non-RTO regions would help ensure that transmission facilities ultimately are constructed. In its reply comments, First Wind supports AWEA's comments. Transmission Access Policy Study Group suggests that the Commission can stimulate the construction of new projects, without expanding transmission providers' obligation to build. It suggests requiring development of a process to obtain construction commitments, with accountability for those commitments. Transmission Access Policy Study Group states that the Final Rule should include a timely post-plan process for: (1) securing commitments by transmission providers

(or others) to build the transmission facilities identified in the regional plan; and (2) holding transmission providers and others that commit to construct transmission facilities included in the regional base model accountable for doing so.

142. On the other hand, Edison Electric Institute argues that the identification of transmission facilities in a transmission plan does not impose an obligation to build them. In addition, Salt River Project asserts that a transmission plan is not a specific blueprint of projects that must be built and states that regional planning provides the valuable service of comparing and contrasting individual potential projects with the decision to build any given project coming after the transmission planning process, with only those projects deemed superior getting built. Salt River Project states that not all projects identified by the plan should be or will be developed. Large Public Power Council points to statements in the Proposed Rule providing that the Commission's intention is not to require construction, and that this decision not to compel construction is grounded in limitations on the Commission's statutory authority.

143. A number of commenters address the issue of whether merchant transmission developers, *i.e.,* those transmission developers that are not seeking regional cost recovery for proposed transmission projects, should be required to participate in the regional transmission planning process. Some commenters state that the Commission should clarify in the Final Rule that merchant transmission developers should not be required to participate in the regional transmission planning process.[134] Clean Line states that, if ratepayers are not bearing development risk and the developer is not seeking regional cost allocation for its project, then it should not be required to participate in the regional transmission planning process. Allegheny Energy Companies note that, in PJM's regional transmission planning process, such merchant transmission developers are not required to participate if they do not wish to do so. New York ISO states that it supports the proposal to not require transmission developers that do not seek to take advantage of a regional transmission cost allocation mechanism to participate in the regional transmission planning process. LS Power states that it understands that merchant transmission developers that did not participate in the regional transmission planning process would still be required to provide to public utility transmission providers the information that is needed, for example, for the reliable operation of the transmission grid.

144. However, others support requiring merchant transmission developers to participate in the regional transmission planning process.[135] APPA states that the reasons for engaging in coordinated planning extend well beyond eligibility for inclusion in the regional transmission cost allocation mechanisms, noting that the development of transmission projects is a time-consuming and expensive endeavor. APPA argues that it is important for transmission planners to know about and fully analyze all of the various transmission alternatives to ascertain the impact of existing and proposed projects on other regional transmission facilities. Transmission Access Policy Study Group is concerned that exempting merchant transmission developers from the regional transmission planning process could cause the mandatory process to plan around *ad hoc* merchant transmission projects and would undermine the benefits of regional transmission planning, such as the development of a right-sized grid, and creates the potential for free ridership. In reply to Clean Line, Edison Electric Institute states that viable merchant transmission projects must be included in the regional transmission planning process, because such projects may have significant reliability, operational, and economic impacts on the transmission system.

145. Finally, some commenters recommend that the Commission strongly encourage nonincumbent participation even in cases where they are not seeking regional cost recovery. California Commissions state that nonincumbent transmission developers that seek cost recovery via rolled-in rates should participate fully in the regional transmission planning process but believes that participation by merchant transmission developers that do not seek such cost recovery should be strongly encouraged to the extent feasible with regard to planning, but not to cost recovery. In its reply comments, Powerex notes that many commenters were opposed to exempting merchant transmission developers and thus recommended that the Commission encourage their participation in the regional transmission planning process.

c. Commission Determination

146. This Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890 identified below. We determine that such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders. This will, in turn, help ensure that the rates, terms and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.

147. Order No. 890 required public utility transmission providers to coordinate at the regional level for the purpose of sharing system plans and identifying system enhancements that could relieve congestion or integrate new resources.[136] The Commission did not specify, however, whether such coordination with regard to identifying system enhancements included an obligation for public utility transmission providers to take affirmative steps to identify potential solutions at the regional level that could better meet the needs of the region. As a result, the existing requirements of Order No. 890 permit regional transmission planning processes to be used as a forum merely to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans. Consistent with the economic planning requirements of Order No. 890, regional transmission planning processes also must respond to requests by stakeholders to perform studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources or loads on an aggregated or regional basis.[137] Again, no affirmative obligation was placed on public utility transmission providers within a region to undertake such analyses in the absence of requests by stakeholders. There is also no obligation for public utility transmission providers within

[134] *E.g.,* Allegheny Energy Companies; Champlain Hudson; Clean Line; H–P Energy Resources; LS Power; and New York ISO.

[135] *E.g.,* APPA; Large Public Power Council; Massachusetts Municipal and New Hampshire Electric; MISO Transmission Owners; National Rural Electric Coops; Nebraska Public Power District; New England States Committee on Electricity; Northern Tier Transmission Group; Ohio Consumers Counsel and West Virginia Consumer Advocate Division; Old Dominion Electric Cooperative; Six Cities; Transmission Agency of Northern California; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

[136] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[137] *Id.*

the region to develop a single transmission plan for the region that reflects their determination of the set of transmission facilities that more efficiently or cost-effectively meet the region's needs.

148. We address these deficiencies in the requirements of Order No. 890 through this Final Rule, beginning with the requirement that public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan. Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements, as discussed further below. When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed non-transmission alternatives on a comparable basis. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of cost allocation.[138]

149. We acknowledge that public utility transmission providers in some regions already meet or exceed this requirement.[139] As with other requirements in this Final Rule, our intent here is to establish a minimum set of obligations for public utility transmission providers that, as some commenters note, are not currently undertaking sufficient transmission planning activities at the regional level. We decline, however, to specify in this Final Rule a particular set of analyses that must be performed by public utility transmission providers within the regional transmission planning process. There are many ways potential upgrades to the transmission system can be studied in a regional transmission planning process, ranging from the use of scenario analyses to production cost or power flow simulations. We provide public utility transmission providers in each transmission planning region the flexibility to develop, in consultation with stakeholders, procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently or cost-effectively. We will review such mechanisms on compliance, using as our yardstick the statutory requirements of the FPA, Order No. 890 transmission planning principles, and our precedent regarding compliance with the Order No. 890 transmission planning principles, and issue further guidance as necessary.[140]

150. Because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, stakeholders must be provided with an opportunity to participate in that process in a timely and meaningful manner. Therefore, we apply the Order No. 890 transmission planning principles to the regional transmission planning process, as reformed by this Final Rule. This will ensure that stakeholders have an opportunity to express their needs, have access to information and an opportunity to provide information, and thus participate in the identification and evaluation of regional solutions. Ensuring access to the models and data used in the regional transmission planning process will allow stakeholders to determine if their needs are being addressed in a more efficient or cost-effective manner. Greater access to information and transparency also will help stakeholders to recognize and understand the benefits that they will receive from a transmission facility in a regional transmission plan. This consideration is particularly important in light of our reforms that require that each public utility transmission provider have a cost allocation method or methods for transmission facilities selected in a regional transmission plan that reflects the benefits that those transmission facilities provide.

151. Specifically, the requirements of this Final Rule build on the following transmission planning principles that we required in Order No. 890: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning.[141] In Order No. 890, we required that each public utility transmission provider adopt these transmission planning principles as part of its individual transmission planning process. In this Final Rule, we expand the Order No. 890 requirements by directing public utility transmission providers to adopt these requirements with respect to the process used to produce a regional transmission plan. We conclude that it is appropriate to do so to ensure that regional transmission planning processes are coordinated, open, and transparent.[142] Accordingly, we require public utility transmission providers to develop, in consultation with stakeholders,[143] enhancements to their regional transmission planning processes, consistent with these transmission planning principles.

152. We conclude that, without the requirement to meet the Order No. 890 transmission planning principles, a regional transmission planning process will not have the information needed to

[138] As discussed in section IV.F.6, below, we conclude that the issue of cost recovery associated with non-transmission alternatives is beyond the scope of this Final Rule, which addresses the allocation of the costs of transmission facilities.

[139] As noted above, to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission. Moreover, to the extent necessary, we clarify that nothing in this Final Rule is intended to modify or abrogate governance procedures of RTOs and ISOs.

[140] In developing their compliance filings, public utility transmission providers and interested parties should review the requirements as set forth in Order No. 890, Order No. 890–A, and our orders on compliance filings submitted by public utility transmission providers for guidance on what each of these transmission planning principles requires. For example, as a starting point, a public utility transmission provider should review the orders addressing its own compliance filings and the compliance filings for public utility transmission providers in its region. We do not address these principles in detail here, except with respect to the consideration of non-transmission alternatives in the regional transmission planning process and other discrete issues raised by commenters.

[141] We do not include the regional participation transmission planning principle and the cost allocation transmission planning principle here because we address interregional transmission coordination and cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation elsewhere in this Final Rule.

[142] Although the explicit requirement for a public utility transmission provider to participate in a regional transmission planning process that complies with the Order No. 890 transmission planning principles identified above is new, we note that the existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these Final Rule requirements.

[143] The term "stakeholder" is intended to include any party interested in the regional transmission planning process. This is consistent with the approach taken in Order No. 890. *See, e.g., Southern Co. Svcs., Inc.,* 127 FERC ¶ 61,282, at P 14–16 (2009).

assess the impact of proposed transmission projects on the regional transmission grid. Additionally, absent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.

153. A number of commenters specifically address the treatment of non-transmission alternatives in the regional transmission planning process. Order No. 890's comparability transmission planning principle requires that the interests of public utility transmission providers and similarly situated customers be treated comparably in regional transmission planning.[144] In response to Order No. 890, public utility transmission providers have identified in their transmission planning processes where, when, and how transmission and non-transmission alternatives proposed by interested parties will be considered. As noted in Order No. 890, the transmission planning requirements adopted here do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed.[145] As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with public utility transmission providers. With that said, the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.[146]

154. We disagree with those commenters that assert that non-transmission alternatives only should be considered in the local transmission planning process. We recognize that generation, demand response, and energy efficiency options often are considered in local resource planning and that transmission often is planned as a last resort. Therefore, when local transmission plans are brought together in a regional transmission planning process to determine if a regional solution can better meet the needs of the region than the sum of local transmission plans, many opportunities for the use of alternative resources will already have been considered. Just as there may be opportunities for regional transmission solutions to better meet the needs of the region, the same could be true for regional non-transmission alternatives. However, the regional transmission planning process is not the vehicle by which integrated resource planning is conducted; that may be a separate obligation imposed on many public utility transmission providers and under the purview of the states.

155. While we require the comparable consideration of transmission and non-transmission alternatives in the regional transmission planning process, we will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. Those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[147] However, we note that in Order Nos. 890 and 890–A, as well as in orders addressing related compliance filings, we have provided guidance regarding the requirements of the Order No. 890 comparability transmission planning principle.[148] Specifically, public utility transmission providers are required to identify how they will evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis.[149]

156. We disagree with concerns raised by certain commenters that the Order No. 890 comparability transmission planning principle may interfere with integrated resource planning.[150] As discussed above, this Final Rule in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over siting, permitting, or construction of transmission solutions.[151] In addition, on compliance with Order No. 890, each public utility transmission provider already has put into place regional transmission planning processes that provide for the evaluation of proposed solutions on a comparable basis.[152] In this Final Rule, the Commission is applying to regional transmission planning the comparability transmission planning principle stated in Order Nos. 890 and 890–A.[153]

157. We agree with commenters that public utility transmission providers should have flexibility in determining the most appropriate manner to enhance existing regional transmission planning processes to comply with this Final Rule. As a result, and consistent with our approach in Order No. 890, we will not prescribe the exact manner in which public utility transmission providers must fulfill the requirements of complying with the regional transmission planning principles. We allow public utility transmission providers developing the regional transmission planning processes to craft, in consultation with stakeholders, requirements that work for their transmission planning region. Consistent with this approach, we will not impose additional rules that would detail consistent planning cycles, impose stakeholder procedures, establish timelines for evaluating regional transmission projects in the regional transmission planning process (including establishing a minimum long-term planning horizons), add any additional requirements to the Order No. 890 dispute resolution transmission planning principle, or establish other planning criteria beyond those in this Final Rule, as requested by some commenters. These are matters best suited to resolution by the public utility transmission providers and stakeholders in the transmission planning region. We also reject Anbaric and PowerBridge's

[144] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494.

[145] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

[146] *Id.* P 454.

[147] We also deny, as beyond the scope of this proceeding, NRG's requests that we direct PJM to determine why its markets are not sending appropriate price signals and that we direct ISOs and RTOs to establish a ''feedback loop.''

[148] *See, e.g.,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 216. *See also, e.g., California Indep. Sys. Operator Corp.,* 123 FERC ¶ 61,283 (2008); *East Kentucky Power Coop.,* 125 FERC ¶ 61,077 (2008).

[149] *See, e.g., NorthWestern Corp.,* 128 FERC ¶ 61,040 at P 38 (2009) (requiring the transmission provider's OATT to permit sponsors of transmission, generation, and demand resources to propose alternative solutions to identified needs and identify how the transmission provider will evaluate competing solutions when determining what facilities will be included in its transmission plan); *El Paso Elec. Co.,* 128 FERC ¶ 61,063 at P 15 (2009) (same); *New York Indep. Sys. Operator, Inc.,* 129 FERC ¶ 61,044, at P 35 (2009) (same). In each of these cases, the Commission stated that tariff language could, for example, state that solutions will be evaluated against each other based on a comparison of their relative economics and effectiveness of performance. Although the particular standard a public utility transmission provider uses to perform this evaluation can vary, the Commission explained that it should be clear from the tariff language how one type of investment would be considered against another and how the public utility transmission provider would choose one resource over another or a competing proposal. *Northwestern Corp.,* 128 FERC ¶ 61,040 at P 38, n.31; *El Paso Elec. Co.,* 128 FERC ¶ 61,063 at P 15, n.25; *New York Indep. Sys. Operator, Inc.,* 129 FERC ¶ 61,044 at P 35, n.26.

[150] *E.g.,* Ad Hoc Coalition of Southeastern Utilities.

[151] *See supra* section III.A.2.

[152] *See, e.g.,* Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[153] *See, e.g., supra* notes 148–49.

suggestion that procedures be developed to treat transmission project information as confidential, outside of the Commission's Critical Energy Infrastructure Information (CEII) requirements and regulations, as this runs counter to the requirement that regional transmission planning processes be open and transparent.

158. Additionally, we note that a public utility transmission provider's regional transmission planning process may utilize a ''top down'' approach, a ''bottom up'' approach, or some other approach so long as the public utility transmission provider complies with the requirements of this Final Rule. Public utility transmission providers have flexibility in developing the necessary enhancements to existing regional transmission planning processes to comply with this Final Rule, based upon the needs and characteristics of their transmission planning region.

159. We also decline to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan, as requested by some commenters. The package of transmission planning and cost allocation reforms adopted in this Final Rule is designed to increase the likelihood that transmission facilities in regional transmission plans will move from the planning stage to construction. In addition, public utility transmission providers already are required to make available information regarding the status of transmission upgrades identified in transmission plans, including posting appropriate status information on its Web site, consistent with the Commission's CEII requirements and regulations.[154] To the extent an entity has undertaken a commitment to build a transmission facility in a regional transmission plan, that information should be included in such postings.[155] We determine that this obligation, together with the reforms we adopt in this Final Rule, are adequate without placing further obligations on public utility transmission providers.

160. The Commission also acknowledges the importance of identifying the appropriate size and scope of the regions over which regional transmission planning will be performed. We clarify that for purposes of this Final Rule, a transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have agreed to participate in for purposes of regional transmission planning and development of a single regional transmission plan. As the Commission explained in Order No. 890, the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.[156] We note that every public utility transmission provider has already included itself in a region for purposes of complying with Order No. 890's regional participation transmission planning principle. We will not prescribe in this Final Rule the geographic scope of any transmission planning region. We believe that these existing regional processes should provide some guidance to public utility transmission providers in formulating transmission planning regions for purposes of complying with this Final Rule. However, to the extent necessary, we clarify that an individual public utility transmission provider cannot, by itself, satisfy the regional transmission planning requirements of either Order No. 890 or this Final Rule.

161. The Commission also clarifies that the obligation to participate in a regional transmission planning process that produces a regional transmission plan that meets the seven transmission planning principles, is not intended to appropriate, supplant, or impede any local transmission planning processes that public utility transmission providers undertake. The objective of this Final Rule is to amend the requirements of Order No. 890 so that regional transmission planning processes not only continue to meet the transmission planning principles established in Order No. 890 but, additionally, produce a regional transmission plan.

162. With regard to comments that seek clarification as to the applicability of the requirements of this Final Rule to transmission projects currently being proposed in existing regional transmission planning processes, we clarify in section II.D above that the requirements of this Final Rule are intended to apply to new transmission facilities. Our intent is to enhance transmission planning processes prospectively to provide greater openness and transparency in the development of regional transmission plans. As also discussed in section II.D above, we recognize that this Final Rule may be issued in the middle of a transmission planning cycle, and we therefore direct public utility transmission providers to explain in their respective compliance filings how they intend to implement the requirements of this Final Rule. In response to comments requesting that the Commission mandate that public utility transmission providers include a funding mechanism to facilitate the participation of in the regional transmission planning process of interested entities that are not market participants, this Final Rule affirms the general approach the Commission took in Order No. 890 regarding the recovery of costs associated with participation in the transmission planning process. There, the Commission acknowledged concerns regarding ''how state regulators and other agencies will recover the costs associated with their participation in the planning process.'' [157] The Commission therefore directed public utility transmission providers to ''propose a mechanism for cost recovery in their planning compliance filings'' and stated that those proposals ''should include relevant cost recovery for state regulators, to the extent requested.'' [158] We decline to expand that directive here to include funding for other stakeholder interests, as requested by certain commenters. However, we also note that, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

163. With regard to the participation of merchant transmission developers in the regional transmission planning process, we conclude that, because a merchant transmission developer assumes all financial risk for developing its transmission project and constructing the proposed transmission facilities, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its transmission project that would otherwise be the basis for securing eligibility to use a regional cost

[154] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

[155] Nothing in this Final Rule limits public utility transmission providers from developing mechanisms to impose an obligation to build transmission facilities in a regional transmission plan, consistent with the requirements below regarding the treatment of nonincumbent transmission developers. Similarly, nothing in this Final Rule preempts or otherwise limits any such obligation that may exist under state or local laws or regulations.

[156] *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527.

[157] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.339 and P 586.

[158] *Id.* n.339.

allocation method or methods.[159] However, we acknowledge the concern of some commenters that a transmission project proposed or developed by a merchant transmission developer has broader impacts than simply cost recovery. Because all electric systems within an integrated network are electrically connected, the addition or cancellation of a transmission project in one system can affect the nature of power flows within one system or on other systems.

164. We therefore conclude that it is necessary for a merchant transmission developer to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. We will allow public utility transmission providers in each transmission planning region, in consultation with stakeholders, in the first instance to propose what information would be required. Public utility transmission providers should include these requirements in their filings to comply with this Final Rule.

165. Although merchant transmission developers must provide information in the regional transmission planning process as discussed herein, to be clear, we emphasize that the transmission facilities proposed by a merchant transmission developer are not subject to the evaluation and selection processes that apply to transmission facilities for which regional cost allocation is sought, as a merchant transmission developer is not seeking to be selected in the regional transmission plan for purposes of cost allocation. However, nothing in this Final Rule prevents a merchant transmission developer from voluntarily participating in the regional transmission planning process (beyond providing the information and data required above) even if it is not seeking regional cost allocation for its proposed transmission project. As we stated in the Proposed Rule, we encourage them to do so. In addition, nothing in this Final Rule limits or otherwise affects the responsibilities a merchant transmission developer may have to fund network upgrades caused by the interconnection of its project with the transmission grid.[160]

4. Consideration of Transmission Needs Driven by Public Policy Requirements[161]

a. Commission Proposal

166. The Proposed Rule would require that transmission needs driven by Public Policy Requirements be taken into account in the local and regional transmission planning process to ensure that each public utility transmission provider's transmission planning process supports rates, terms, and conditions of transmission service in interstate commerce that are just and reasonable and not unduly discriminatory or preferential. The Proposed Rule would require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements.[162] The Commission noted that this proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the Order No. 890 economic planning studies transmission planning principle in the transmission planning process.[163] If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then the Proposed Rule would require that the public utility transmission provider must make that demonstration in its compliance filing.[164]

167. The Proposed Rule would require each public utility transmission provider to coordinate with its stakeholders to identify Public Policy Requirements that are appropriate to include in its local and regional transmission planning processes.[165] The Proposed Rule stated that, after consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations.

168. The Proposed Rule sought comment on how planning criteria based on Public Policy Requirements should be formulated, including whether it would be more appropriate to use flexible criteria rather than ''bright line'' metrics when determining which transmission projects are to be included in a regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a transmission project is included in a regional transmission plan, and whether the use of ''bright line'' metrics may inappropriately result in alternating inclusion and exclusion of a single transmission project over successive planning cycles and thus create inappropriate disruptions in long-term transmission planning.[166]

b. Comments

169. In general, most commenters support the Commission's proposal that each public utility transmission provider must amend its OATT such that local and regional transmission planning processes explicitly provide for the consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.[167] Support came from all sectors of the industry,

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[159] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 99.

[160] We note that, to the extent a merchant transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it also will be required to comply with all applicable obligations, including registration with NERC. Under section 215, all users, owners, or operators of the bulk power system must register with NERC for performance of applicable reliability functions. The registration with NERC will help ensure that merchant transmission developers provide all appropriate information to be used in transmission system planning and assessment studies. *See* 16 U.S.C. 824o(g) (''Reliability Reports—The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.''); *see also Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, at P 803, *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006). Concerns regarding when NERC registration would be triggered should be addressed in a NERC registration process.

[161] *See supra* P 2 (defining Public Policy Requirements).

[162] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64.

[163] *Id.*

[164] *Id.* P 66.

[165] *Id.* P 65.

[166] *Id.* P 70.

[167] *E.g.,* Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission Agency of Northern California; Western Grid Group; and Wind Coalition.

including public utilities, municipal and cooperative utilities, renewable generators, transmission developers, state commissions, and consumer and public interest representatives. While most commenters support the proposal to include public policy requirements in transmission planning processes, a number seek clarification or request that the Commission provide additional guidance.

170. With regard to what constitutes a public policy requirement, some commenters seek to limit the definition to state and federal laws and regulations[168] while others seek a more flexible approach. For example, Omaha Public Power District supports the Commission's proposal only if such public policy requirements are established by state or federal laws or regulations applicable to all entities in the relevant planning region. East Texas Cooperatives believes that Omaha Public Power District's proposal strikes a reasonable balance. Similarly, National Rural Electric Coops state that the Commission should not empower stakeholders to use the transmission planning process to impose and enforce new resource planning requirements that lack the sanction of state or federal law in the planning region. First Energy Service Company argues that only enforceable requirements that are embodied in state or federal law should be eligible for inclusion in transmission planning processes. Duke states that the Final Rule should make unambiguous that the public policy aspect of regional and interregional planning refers only to those transmission projects driven by the need to comply with state and/or federal laws, rules, and/or regulations and that it supports limiting the requirement to public policies that drive the need for transmission.

171. Likewise, PJM states that the Commission should make clear that the responsibility of the transmission planner to plan for public policy criteria is triggered by the clear and formal identification of those public policy criteria identified by Congress or state policymakers through publicly issued laws or regulations and recognize that the transmission planner would need to refer to the states to reconcile conflicting policies that cannot both be reasonably accommodated under a cost-effective and efficient regional transmission plan. In their reply comments, APPA, PSEG Companies, ISO/RTO Council, and Illinois Commerce Commission also caution about transmission planners picking and choosing the public policies that would be considered in transmission planning processes.

172. In their reply comments, ISO/RTO Council suggest that the Final Rule make clear that public policy objectives are limited to those developed by federal or state executive, legislative, and regulatory bodies with authority to adopt such objectives, that ISOs and RTOs may defer to regional state committees on identifying and reconciling individual state public policy goals, that states should utilize the authority under section 216(i) of the FPA to enter into regional compacts to ensure that recommendations pass constitutional muster and otherwise have a suitable legal foundation, and that stakeholders should advocate means of implementing state public policy mandates to the states rather than to ISOs/RTOs.

173. Several comments focus on the role of states in the identification of public policy requirements and what constitutes such a requirement. Many request that the Final Rule expressly acknowledge the role of the state regulatory agencies and governors.[169] For example, PUC of Nevada supports the Commission's concept to require that public policies be incorporated into transmission planning and states that the Final Rule should specify the role state regulatory commissions and governors play in ensuring that the transmission plan accurately reflects state policies and, where there are inconsistencies in the utility's interpretation of the state's public policy versus that of the state regulatory commissions and governors, the Commission should give deference to the regulatory commissions' and governors' interpretation. PUC of Nevada also notes that the Final Rule does not include an oversight mechanism.

174. New England States Committee on Electricity conditions its support for the Commission's proposal on states identifying the policies established in law and regulations to be considered in transmission analysis. New York PSC comments that the Commission should modify the process to allow states to identify which state-level policies should be included in the transmission planning process. It also asks the Commission to clarify that these policies may include public policies derived pursuant to such statutory or regulatory authority, such as those created pursuant to regulatory orders or state energy plans and to allow states to identify state-level policies for inclusion in those plans, not stakeholders. In reply comments, California PUC also states that the Commission should not establish prescriptive criteria regarding what policy goals are to be included. City of Los Angeles Department of Water and Power states that the Commission's proposal should be expanded to include local laws and regulations, noting that many requirements of entities such as itself are grounded in such local mandates.

175. NARUC notes that states will not turn over their policy authority to planning entities for inclusion in a Commission tariff and states that, while it is valuable to have transmission planning processes incorporate public policy considerations, a Commission tariff cannot mandate particular policy approaches. NARUC explains that transmission planners should not be required to determine unwritten public policy requirements, and that the Final Rule should explicitly recognize the governmental role, particularly at the state level, in providing policy input into the transmission planning processes, rather than directing the planners to consult with all stakeholders. NARUC states that the Final Rule should make explicit that any provisions do not impede or interfere with state commission authority to accept or approve integrated resource plans, make decisions about generation, demand-side resources, resource portfolios, or to modify policy based on cost thresholds. East Texas Cooperatives, First Wind, and Florida PSC express their support for NARUC's position.

176. Connecticut & Rhode Island Commissions state that the Commission should not prescribe any particular public policy requirement that must be considered or excluded from the transmission planning process. Moreover, they argue that the states, not transmission utilities and planners, must retain their jurisdiction as the ultimate arbiter on the issue of whether a transmission project is the most beneficial, lowest cost, or most prudent decision for achieving a state public policy goal. North Carolina Agencies assert that the regional transmission planning processes should not decide how to meet state and federal policy requirements, and that the FPA gives the Commission no authority to determine what resources should be used by load-serving entities, regardless of whether or not those resources are

[168] *E.g.,* Omaha Public Power District; Exelon; First Energy Services; PJM; New York ISO; and Transmission Agency of Northern California.

[169] *E.g.,* Connecticut & Rhode Island Commissions; Massachusetts Departments; PUC of Nevada; and New England States Committee on Electricity.

needed to meet public policy requirements.

177. Others seek more flexibility in defining what constitutes a public policy requirement.[170] For example, Pacific Gas & Electric asks that the Final Rule clarify that local and regional transmission planning processes for public utility transmission providers consider state or federal public policy objectives rather than identifying or referring to specific laws and regulations. NextEra seeks clarification that any type of legal or regulatory requirements affecting transmission development should be included in the transmission planning process, noting that the EPA has established a schedule for issuing of a host of Clean Air Act rules governing other emissions from electric generating units. Iberdrola Renewables states that any state and federal renewable portfolio requirements and any state and federal greenhouse gas emission reduction or climate change policies, including requirements or standards that take effect in future years, should be considered in the transmission expansion plan. Atlantic Wind Connection states that the Commission should broaden the phrase ''public policy requirements'' used in the Proposed Rule to include public policy initiatives or something similar to reflect the broad, non-compulsory nature of the policy environment.

178. Several commenters, including some consumer advocates and public interest organizations, recommend that the Commission specify the state and federal policy requirements that utilities, must, at a minimum, take into account in their transmission planning processes.[171] Some suggest including: (1) Renewable portfolio standards; (2) energy efficiency standards and mandates; (3) CO_2 emissions reduction targets/requirements; (4) NAAQS attainment and interstate air pollution reductions; (5) EPA utility sector regulations; and (6) federal and state land management, land use, wildlife conservation and zoning policies and procedures intended to facilitate the siting of renewable energy.[172] In its reply comments, EarthJustice endorses this view. Twenty-six Public Interest Organizations state that comparable consideration of all resource options available to meet various public policy requirements is essential to minimizing utilities' opportunities for undue discrimination. Ohio Consumers' Counsel and West Virginia Consumer Advocate Division state that transmission providers should be required describe the role that each ''public policy'' would play in the transmission planning process. Michigan Citizens Against Rate Excess state that while both reliability and public policy requirements should be considered as part of the same plan, they should be analyzed separately and the transmission plan should explain how these projects may complement or contradict each other.

179. Commenters that believe that the Commission should take a broader view of what public policy requirements are to be considered by transmission providers and their stakeholders, argue, for example, that the transmission planning process must be sufficiently flexible to include reasonably foreseeable public policy objectives not yet explicitly required by existing law or regulation and also to consider ''at risk'' generation.[173] Atlantic Wind Connection suggests the adoption of an unambiguous requirement to plan transmission additions needed to accommodate public policy initiatives and suggests that the Commission require specific tariff provisions describing how transmission facilities that accommodate and facilitate public policy initiatives would be planned for and evaluated. AWEA states that the Commission should clarify that public policy requirements are not to be narrowly construed and that expected future public policy requirements as well as existing ones should be considered.

180. However, in reply, a number of commenters take exception with the suggestion that possible or likely future public policies should be considered in the transmission planning process stating, among other things, that it could result in constantly moving targets, unfocused transmission planning, regulatory uncertainty, and the RTOs or the Commission assuming the roles of Congress and the states.[174] For example, Exelon argues that the Final Rule should specify that planning for public policy should not include aspirational goals. Likewise, Large Public Power Council's reply comments state that transmission planners should not be required to take into account anticipated public policies. Xcel also believes that the requirement to consider public policy directives in developing transmission plans should focus on established policies, rather than anticipated or potential future obligations.

181. Among those seeking flexibility and recognition of regional differences,[175] Edison Electric Institute and Northeast Utilities state that the Commission should allow flexibility in defining the types of public policy requirements; determining implementation details, such as the process to identify public policy requirements; and how transmission system needs would be selected once an appropriate public policy requirement is identified. Northern Tier Transmission Group states that to the extent that a transmission provider maintains an obligation to serve retail load, its merchant/load-serving function will identify and quantify the relevant public policy requirements, which will then be accounted for in its local transmission plan. Any additional public policy objectives should be at the discretion of regional planning groups. Transmission Access Policy Study Group states that the Final Rule should clarify the reference to state and federal policy requirements, so that it includes state regulatory commission orders and regulations and local governmental mandates on load-serving entities; and expressly identify FPA section 217(b)(4) as a federal public policy requirement that the regional transmission planning process must consider.

182. Other commenters have ideas on or questions about how public policy requirements are to be included and implemented. Exelon states that the Commission should adopt principles to help head off stalemates: (1) Transmission planning must include likely retirements of plants subject to environmental regulations; (2) encompass only laws actually in effect in determining the impact on generation capacity; (3) require transmission planners to take into account all the actual terms of state and federal laws and regulations for which transmission expansion is planned; (4) require a region to show that its stakeholder-endorsed policy would not cause any harm or costs to other regions; (5) the full cost of resources must be transparent and considered in the transmission planning process, based on

[170] *E.g.,* New Jersey Division of Rate Counsel and Integrys.

[171] *E.g.,* EarthJustice; 26 Public Interest Organizations; and National Audubon Society.

[172] *E.g.,* Conservation Law Foundation; Energy Future Coalition Group; E.ON Climate & Renewables North America; Environmental Defense Fund; Environmental NGOs; Natural Resources Defense Council; Sonoran Institute; and Wilderness Society and Western Resource Advocates.

[173] *E.g.,* Iberdrola Renewables.

[174] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Coalition for Fair Transmission Policy; East Texas Cooperatives; Large Public Power Council; National Rural Electric Coops; and New England States Committee on Electricity.

[175] *E.g.,* ISO/RTO Council; ISO New England; PJM; New York ISO; SPP; MISO; New York Transmission Owners; NEPOOL; and MISO Transmission Owners.

sound economic principles; and (6) require that planning for renewable energy resources be done with the objective of minimizing total costs. MISO states that the proposal should be expanded to include a requirement to, when prudent, pursue appropriate transmission expansion initiatives to facilitate the compliance of public policy requirements by entities within the transmission provider's footprint that are subject to such requirements.

183. PJM states that the actual development of transmission to address public policy standards requires: (1) Further direction as to how such standards should be reflected in implementable planning assumptions; and (2) a legally empowered coordination among states with shared policy agendas allowing regional projects to be sited and permitted because they are ''needed'' to meet the multistate collective's shared policy agenda. Old Dominion and Atlantic Wind Connection support PJM's suggested holistic approach to transmission planning. In response, however, Consolidated Edison and Orange & Rockland argue that PJM's comments do not adequately reflect the Proposed Rule's objective to respect regional methods and urge the Commission to reject PJM's top down approach.

184. Pattern Transmission states that the Commission should require public utility transmission providers to specify when transmission upgrade projects are categorized as public policy-driven projects and when the transmission facilities are considered solely through the generator interconnection process.

185. Others offer for Commission consideration their desired outcomes from including Public Policy Requirements in regional transmission planning.[176] For example, Transmission Agency of Northern California seeks confirmation that simply characterizing a project's purpose as meeting a public policy requirement should not provide that project a presumption of inclusion in the regional transmission planning process. Transmission Access Policy Study Group states that the Commission should urge transmission providers to adopt a ''no regrets'' strategy that focuses on constructing transmission facilities needed under multiple potential power supply and public policy scenarios, which lead to a ''right-sized'' grid with greater flexibility to respond to changing technology, resource options, and customer needs. Old Dominion also asks that the Final Rule make clear that the directive to plan for public policy laws or regulations is for transmission planning only, not for design and construction or to improve power supply.

186. Western Grid Group states that, at a minimum, the Commission should require regional plans to address a planning horizon of at least 20 years and to evaluate environmental and economic constraints and public interest concerns over that horizon as a basis for the development of such plans. Powerex cautions that the consideration of public policy factors not result in transmission planning and cost allocation processes that elevate the needs of certain customers over others in the transmission planning process and should preserve competitive wholesale power markets.

187. Commenters also offer ideas on timing and scope. Some commenters argue that only federal and state laws and regulations in effect during the transmission planning cycle should be considered as public policy requirements in the regional transmission planning process.[177] East Texas Cooperatives, however, believes that a better approach is to let participants in the transmission planning process advocate for their own needs and interests (which by necessity will reflect the need to comply with policies contained in applicable federal and state law), and then allow the transmission planning process to sort out these interests within the existing Order No. 890 transmission planning framework. In response to such comments, however, AEP contends that planning for only current regulatory requirements is too narrow a formulation that would result in underinvestment in transmission infrastructure. AEP suggests that the transmission planning process consider reasonably foreseeable future regulatory requirements given their likely impact on the power system, citing NERC's analysis of potential impacts of EPA regulations on generation.

188. A number of commenters believe either that existing regional transmission planning processes already consider public policy requirements and thus OATT revisions may therefore be unnecessary.[178] East Texas Cooperatives state that they agree with the Commission's preliminary finding, but disagree as to the need for any revisions to the OATT as transmission planning already takes into account public policy requirements established by state or federal laws or regulations in accordance with Order No. 890's transmission planning requirements, as well as with Commission policy that has evolved over the years. Many commenters in ISO and RTO regions argue that the transmission planning processes administered by those entities already address or largely address public policy issues.[179] For example, New York ISO supports the Commission's proposal but states that existing transmission planning rules already provide for consideration of public policy requirements in many regions. Transmission Dependent Utility Systems recommend that the Commission clarify that nothing in the existing *pro forma* OATT prohibits the consideration of public policy requirements in the transmission planning processes and, to the extent a transmission provider believes its particular OATT does preclude such considerations, the Final Rule should direct compliance filings to remove the language allegedly prohibiting such consideration.

189. Some commenters raise additional concerns, including how public policy considerations would be incorporated into a transmission provider's local and regional transmission planning process including whether the proposal is intended to modify or incorporate generator interconnection requests into the ''local and regional transmission planning process;'' whether a project proposed to satisfy transmission needs driven by public policy requirements are to be planned for and considered separately from reliability and economic projects; whether regional transmission planning organizations are required to create a separate category of public policy-driven transmission projects or whether they are to be in concert with reliability and economic criteria during the transmission planning process.[180]

190. Coalition for Fair Transmission Policy is concerned that the Proposed Rule might be interpreted as requiring transmission planning processes to make decisions as to how best to meet applicable public policy requirements on behalf of those entities on whom the

[176] *E.g.,* Pattern Transmission; Transmission Agency of Northern California; and Transmission Access Policy Study Group.

[177] *E.g.,* National Rural Electric Coops; City of Santa Clara; Michigan Citizens Against Rate Excess; Exelon; East Texas Cooperatives; and Coalition for Fair Transmission Policy.

[178] *E.g.,* Washington Utilities and Transportation Commission; Alliant Energy; Xcel; Bonneville Power; Westar; Sacramento Municipal Utility District; National Rural Electric Coops; East Texas Cooperatives; WECC; WestConnect; Georgia Transmission Corporation; Southern Companies; and Ad Hoc Coalition of Southeastern Utilities.

[179] *E.g.,* New England Transmission Owners; Alliant Energy; and New York ISO.

[180] *E.g.,* NV Energy; Long Island Power Authority; and Bonneville Power.

requirements are placed. Therefore, it states that decisions on how load-serving entities within regions should meet state or federal public policy requirements should continue to be made by those with responsibilities to meet the requirements, based on federal and state law and applicable regulations, and recommends that the Final Rule make this clear.

191. PPL Companies state that basing transmission planning decisions on state public policy directives may lead to undue discrimination among generators and, thus, run afoul of the FPA requirement that all users of the transmission system be treated in a non-discriminatory manner. It states that the Commission should direct transmission planners to make sure that pre-existing rights are preserved and accommodated under the Proposed Rule's transmission planning principles, just as the Commission preserved grandfathered transmission contracts under Order No. 888 and grandfathered interconnection agreements under Order No. 2000.

192. New Jersey Board believes there needs to be recognition of planning for public policy goals in terms of reliability. It asserts that focusing solely on public policy goals as the driving force in the transmission planning process would raise issues as to which policy should receive the greatest emphasis, and would cause conflict in the transmission planning process over which goals to incorporate. New Jersey Board recommends that transmission plans incorporate public policy goals in a fashion that has these projects evaluated similarly for reliability and economic purposes.

193. Some commenters generally oppose the proposal to require public policy considerations in transmission planning.[181] PSEG Companies state that the Commission's public policy planning approach should not be adopted, arguing that the proposal would result in public utility transmission providers establishing an unduly preferential practice favoring renewable energy resources over other types of resources. Finally, PSEG Companies are concerned that the proposal could result in overbuilding or underbuilding the transmission grid. Ad Hoc Coalition of Southeastern Utilities asserts that there is no dependable means to translate abstract notions of public policy into the transmission planning process, except to the extent it has a bearing on transmission demand. Energy Consulting Group states that interregional planning should not be used as an instrument of public policy but should incent development of transmission improvements to afford the public access to all types of generation that is economic and minimizes its power costs. APPA believes that any transmission provider wishing to incorporate specific state policy requirements or other objectives into its transmission planning protocols should do so through case-by-case tariff filings under FPA section 205.

194. Electricity Consumers Resource Council and the Associated Industrial Groups are concerned with mandatory interjection of state public policy considerations into the transmission planning process and how, in practice, this is expected to work, given public policy differences among states, and they are concerned that the Proposed Rule delegates to ISOs and RTOs the authority to impose the public policy requirements of one state on another without sufficient democratic or procedural checks and balances.

195. Some commenters agree with the proposal to coordinate identification of public policy requirements. These commenters generally state that flexibility is needed given the regional variation in: public policy objectives; types and location of resources; and regional needs, provided that transmission providers seek input from state authorities and other stakeholders.[182] MISO Transmission Owners ask that the Commission not mandate what public policy requirements must be considered, but should allow individual transmission providers to work with stakeholders to identify public policy requirements applicable to the state(s) or region in which the transmission provider is located; they also state that transmission planning regions should not be required to plan for or contribute to the costs of enabling compliance with public policy requirements enacted outside of their region without the agreement of all regions affected.

196. Some commenters agree that public utility transmission providers should be required to specify the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements. 26 Public Interest Organizations assert that the Commission should require all transmission providers to incorporate certain best practices in the OATT to achieve the Commission's goal. These include: (1) Minimum coordination agreement requirements for plan development; (2) required actions to assure robust participation in regional plan development by non-market participant stakeholders; and (3) minimum requirements to ensure fair and comparable consideration of all options to meet public policy requirements. Clean Energy Group states that transmission planners should be required to identify the specific public policy goals that would be considered in the planning cycle after consultation with stakeholders, including state policy makers. Additionally, it states that transmission providers should be required to disclose and document how public policy considerations were taken into account.

197. Other commenters would like flexibility in this regard. Edison Electric Institute states that the Commission should not require transmission providers to identify in their tariff each specific public policy requirement that may be taken into consideration but should allow flexibility. ISO New England and Kansas City Power & Light and KCP&L Greater Missouri similarly argue that the Commission should specify that it would not become a requirement within the tariff to list each specific public policy requirement. However, in reply, Conservation Law Foundation argues that the policies should be reflected in the OATT and asks that the Final Rule hold planning authorities responsible for applying those policies that are germane to a given process or decision. In their reply comments, Maine Parties point to MISO tariff provisions that show that ISOs and RTOs can develop tariff provisions that include criteria for identifying public policy projects, and request that the Commission be explicit about the role it expects ISOs and RTOs to play in identifying state and federal public policies and in identifying criteria for selecting projects.

198. In response to the Commission's question regarding the use of ''bright line'' metrics when evaluating potential transmission projects, the majority of commenters that provided input on this issue support a flexible approach.[183]

[181] *E.g.,* PSEG Companies; First Energy Service Company; Ad Hoc Coalition of Southeastern Utilities; National Rural Electric Coops; Southern Companies; Large Public Power Council; Nebraska Public Power District; and Long Island Power Authority.

[182] *E.g.,* American Transmission; Atlantic Grid; Consolidated Edison and Orange & Rockland; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; NEPOOL; New England Transmission Owners; New York Transmission Owners; and Northeast Utilities.

[183] *E.g.,* Anbaric and PowerBridge; Atlantic Grid; AWEA; First Wind; Integrys; National Rural Electric Coops; New Jersey Division of Rate Counsel; New York ISO; New York Transmission Owners; NextEra; Northeast Utilities; Northern Tier Transmission Group; Organization of MISO States; PJM; SPP; WECC; and Westar.

They generally agree that transmission providers should be provided flexibility to take into account the multiple reliability, economic, and public policy-based benefits a single project may provide. They express concern that projects that address reliability, economic, and public policy initiatives may not be pursued because the transmission provider may not be allowed to include the project in the regional plan because of the technical failure to meet a bright line test. AWEA notes that existing transmission planning processes that rely on bright line criteria do not accommodate well the integration of renewable resources into the grid. NRECA states that bright line metrics are unnecessary because load-serving entities' planning requirements implicitly include established public policy requirements.

199. While expressing the need for flexibility, some commenters note that the Commission should establish in the Final Rule some level of specificity as to how the regional plan should consider projects designed to meet public policy requirements. NEPOOL suggests that the Commission grant deference to the states in a planning region with regard to how they would want public policy requirements to be considered in the context of regional planning. SPP echoes this, stating that the Commission should afford transmission providers, state regulatory commissions, and stakeholders flexibility to develop strategies and metrics that appropriately consider the needs and reflect the existing structure of the transmission system in the region. First Wind recognizes that certain public policy considerations could require a bright line metric to ensure they be included in a regional plan, while others could be more general and flexible.

200. Others, however, argue that bright line metrics are necessary to avoid discrimination in the transmission planning process.[184] City and County of San Francisco and LS Power both assert that removing bright line criteria would lead to unfair results. City and County of San Francisco assert that without bright line criteria, end-users could be penalized because of different cost allocation methods associated with each distinct criterion.

201. Some commenters support a balanced approach of using both bright line and flexible metrics. While Organization of MISO States cautions against the establishment of rigid bright line metrics, it notes that an overly flexible approach could allow for higher cost projects than are actually needed. It states that the Commission should seek a reasonable balance by ordering transmission planners to start with defined criteria and then look further into more flexible options that could provide an optimal solution to a number of perceived needs. Dominion states that both flexible and bright line criteria may be needed for some multi-purpose projects. Dominion explains that the benefit of reliability projects must be assessed against bright line criteria. However, when considering other benefits, Dominion states that more flexibility is needed. Minnesota PUC and Minnesota Office of Energy Security recommend that bright line metrics be used as a first pass in the transmission planning process, but more flexible criteria could be used to assess each project further.

202. Finally, there are some commenters that argue that the Commission's proposal may lead to undesirable outcomes. Large Public Power Council states that requiring each public utility transmission provider to coordinate with customers and other stakeholders to identify relevant state and federal laws and regulations would be unnecessary, potentially confusing, and ultimately counterproductive. Long Island Power Authority states that the Proposed Rule did not identify how a regional transmission planning group encompassing multiple states is to decide which state's ''public policy requirements'' must be satisfied through the transmission planning process. It expresses concern that the apparent default solution of incorporating every state's public policy requirements into the transmission planning process to the extent feasible, may distort the transmission planning process, lead to over-construction of transmission facilities and consequently increase the costs to be allocated. Nebraska Public Power District states that the discretion that this approach would interject into the transmission planning process would seem to be an open door to potential discrimination, and a nightmare to enforce, as parties debate whether planning adequately responds to a variety of potentially competing policies.

c. Commission Determination

203. The Commission requires public utility transmission providers to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[185] As discussed in section II above, the reforms adopted below are intended to ensure that the local and regional transmission planning processes support the development of more efficient or cost-effective transmission facilities to meet the transmission needs driven by Public Policy Requirements, which will help ensure that the rates, terms and conditions of jurisdictional service are just and reasonable. Moreover, these reforms will remedy opportunities for undue discrimination by requiring public utility transmission providers to have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by Public Policy Requirements, rather than the public utility transmission provider planning only for its own needs or the needs of its native load customers. Our decision here to require transmission planning to include the consideration of transmission needs driven by Public Policy Requirements is supported by the numerous commenters who generally agree with the proposed reforms.[186]

204. Under the existing requirements of Order No. 890, there is no affirmative obligation placed on public utility transmission providers to consider in the transmission planning process the effect that Public Policy Requirements may have on local and regional transmission needs.[187] We agree with

[184] *E.g.,* City and County of San Francisco; LS Power; New Jersey Division of Rate Counsel; and Western Independent Transmission Group.

[185] To the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some ISO/RTO regions, the requirements of this Final Rule with regard to Public Policy Requirements apply only to the regional transmission planning process.

[186] *E.g.,* Allegheny Energy Companies; American Transmission; Anbaric and PowerBridge; Arizona Corporation Commission; Arizona Public Service Company; Atlantic Grid; AWEA; California Commissions; California ISO; Clean Energy Group; Connecticut & Rhode Island Commissions; Consolidated Edison and Orange & Rockland; DC Energy; Delaware PSC; Dominion; Duke; Duquesne Light Company; EarthJustice; Exelon; First Wind; Iberdrola Renewables; Integrys; ISO New England; ISO/RTO Council; Maine PUC; Massachusetts Departments; Massachusetts Municipal and New Hampshire Electric; MISO; MISO Transmission Owners; National Audubon Society; National Grid; New England States' Committee on Electricity; New Jersey Board; New Jersey Division of Rate Counsel; New York PSC; NextEra; Northeast Utilities; Northern Tier Transmission Group; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; Old Dominion; Pacific Gas & Electric; Pattern Transmission; Pennsylvania PUC; PHI Companies; PJM; PUC of Nevada; San Diego Gas & Electric; Southern California Edison; Sunflower and Mid-Kansas; Transmission Dependent Utility Systems; Transmission Access Policy Study Group; Transmission Agency of Northern California; Western Grid Group; and Wind Coalition.

[187] In response to Transmission Dependent Utility Systems, we note that nothing in the existing *pro forma* OATT affirmatively prohibits consideration

the concerns of many commenters that, without having in place procedures to consider transmission needs driven by Public Policy Requirements, the needs of wholesale customers may not be accurately identified.[188] While we understand that some public utility transmission providers already do have processes in place to determine whether transmission needs reflect Public Policy Requirements, others do not. We correct this deficiency through the requirements below, which are intended to enhance, rather than replace, existing transmission planning obligations under Order No. 890. Moreover, as with other reforms adopted in this Final Rule, these requirements are intended to be an additional set of minimum obligations for public utility transmission providers and are not intended to preclude additional transmission planning related activities.

205. In response to commenters seeking greater clarity as to how transmission needs driven by Public Policy Requirements must be considered by public utility transmission providers, we clarify that by considering transmission needs driven by Public Policy Requirements, we mean: (1) The identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those needs. We therefore direct public utility transmission providers to amend their OATTs to describe the procedures by which transmission needs driven by Public Policy Requirements will be identified in the local and regional transmission planning processes and how potential solutions to the identified transmission needs will be evaluated in the local and regional transmission planning processes. We discuss each of these requirements in turn.

206. First, public utility transmission providers must establish, in consultation with stakeholders, procedures under which public utility transmission providers and stakeholders will identify those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated. Various commenters express concern that a public utility transmission provider should not have an open-ended obligation to undertake costly and time-consuming studies to evaluate the potential impact that every Public Policy Requirement might have on transmission development. As noted by Connecticut & Rhode Island Commissions, for example, entities subject to particular requirements may intend to meet them in ways that do not involve the planning of transmission within the local or regional transmission planning processes. In other circumstances, there may be disagreement among the various entities subject to competing Public Policy Requirements as to whether it is appropriate to consider the impact of complying with those laws and regulations in the transmission planning process.

207. We do not in this Final Rule require the identification of any particular transmission need driven by any particular Public Policy Requirements. Instead, we require each public utility transmission provider to establish procedures for identifying those transmission needs driven by Public Policy Requirements for which potential transmission solutions will be evaluated in the local or regional transmission planning processes. As part of the process for identifying transmission needs driven by Public Policy Requirements, such procedures must allow stakeholders an opportunity to provide input, and offer proposals regarding the transmission needs they believe are driven by Public Policy Requirements. To the extent such procedures identify no transmission needs driven by a Public Policy Requirement, the relevant public utility transmission providers are under no obligation to evaluate potential transmission solutions.

208. We allow for local and regional flexibility in designing the procedures for identifying the transmission needs driven by Public Policy Requirements for which potential solutions will be evaluated in the local or regional transmission planning processes. The effects of Public Policy Requirements on transmission needs are highly variable based on geography, existing resources, and transmission constraints. We therefore conclude that it is appropriate to require public utility transmission providers, in consultation with their stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by Public Policy Requirements in their area, subject to our review on compliance. At a minimum, however, we require that all such procedures allow for input from stakeholders, including but not limited to those responsible for complying with the Public Policy Requirement(s) at issue and developers of potential transmission facilities that are needed to comply with one or more Public Policy Requirements.

209. We decline to require that transmission needs driven by Public Policy Requirements be identified by a particular entity or subset of stakeholders. However, all stakeholders must have an opportunity to provide input and offer proposals regarding the transmission needs they believe should be so identified, as discussed above. In other words, while the procedures adopted by public utility transmission providers in response to this Final Rule must allow all stakeholders to bring forth any transmission needs they believe are driven by Public Policy Requirements, those procedures must also establish a just and reasonable and not unduly discriminatory process through which public utility transmission providers will identify, out of this larger set of needs, those needs for which transmission solutions will be evaluated. Some public utility transmission providers might conclude, in consultation with stakeholders, to develop procedures that rely on a committee of load-serving entities, a committee of state regulators, or a stakeholder group to identify those transmission needs for which potential solutions will be evaluated in the transmission planning processes.[189] Another example would be the case where a public utility transmission provider identifies such transmission needs itself on behalf of its customers, following consultation with stakeholders, including participating state regulators. However, to ensure that requests to include transmission needs are reviewed in a fair and non-discriminatory manner, we require public utility transmission providers to post on their Web sites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated. We conclude that this posting requirement is necessary to provide the Commission and interested parties with information as to how the identification procedures are

of the effect of Public Policy Requirements on transmission needs.

[188] *E.g.,* National Grid; NextEra; AWEA; Atlantic Grid; Delaware PSC; Anbaric and PowerBridge; and Conservation Law Foundation.

[189] As noted below, we strongly encourage states to participate actively in the identification of transmission needs driven by Public Policy Requirements. Public utility transmission providers, for example, could rely on committees of state regulators or, with appropriate approval from Congress, compacts between interested states to identify transmission needs driven by Public Policy Requirements for the public utility transmission providers to evaluate in the transmission planning process.

implemented by public utility transmission providers.

210. We decline in this Final Rule to require the identification of any particular set of transmission needs driven by any particular Public Policy Requirements in the local and regional transmission planning processes of public utility transmission providers. To the extent that implementation of the procedures required here results in a suggested transmission need not being evaluated for potential solutions in the local or regional transmission planning process, the relevant public utility transmission provider(s) are under no obligation under this Final Rule to evaluate the potential effect of the associated Public Policy Requirement on transmission development. This includes proposals to evaluate the need for particular transmission facilities proposed by transmission developers to comply with Public Policy Requirements. While these entities may continue to offer their proposed transmission facilities in the local or regional transmission planning process as a potential solution to transmission needs, such proposals would not be evaluated in the transmission planning process as driven by a Public Policy Requirement.

211. With regard to the evaluation of potential solutions to the identified transmission needs driven by Public Policy Requirements, we again leave to public utility transmission providers to determine, in consultation with stakeholders, the procedures for how such evaluations will be undertaken, subject to the Commission's review on compliance and with the objective of meeting the identified transmission needs more efficiently and cost-effectively.[190] As noted in our discussion of regional transmission planning in section III.A above, there are many ways potential upgrades to the transmission system can be evaluated, ranging from the use of scenario analyses to production cost or power flow simulations. At a minimum, however, this process must include the evaluation of proposals by stakeholders for transmission facilities proposed to satisfy an identified transmission need driven by Public Policy Requirements.[191] However, as with any proposed solution offered in the local or regional transmission planning processes for transmission needs driven by reliability issues or economic considerations, there is no assurance that any proposed transmission facility will be found to be an efficient or cost-effective solution to meet local or regional needs.

212. In response to commenters that urge us to recognize the role of the states in transmission planning, especially as it relates to compliance with Public Policy Requirements, we clarify that nothing in this Final Rule is intended to alter the role of states in that regard. Through this Final Rule, we are requiring public utility transmission providers to provide an opportunity to all stakeholders, including state regulatory authorities, to provide input on those transmission needs they believe are driven by Public Policy Requirements, to the extent they are not already doing so. We are not dictating any substantive result with regard to compliance with Public Policy Requirements. In Order No. 890, the Commission stated its expectation that ''all transmission providers will respect states' concerns'' when engaging in the regional transmission planning process.[192] This is equally true with regard to the consideration of transmission needs driven by Public Policy Requirements. We strongly encourage states to participate actively in both the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs.

213. We therefore do not believe our reforms are inconsistent with state authority with respect to integrated resource planning, as suggested by some commenters. Indeed, we believe that the requirements imposed herein complement state efforts by helping to ensure that potential solutions to identified transmission needs driven by Public Policy Requirements of the states can be evaluated in local and regional transmission planning processes. To be clear, however, while a public utility transmission provider is required under this Final Rule to evaluate in its local and regional transmission planning processes those identified transmission needs driven by Public Policy Requirements, that obligation does not establish an independent requirement to satisfy such Public Policy Requirements. In other words, the requirements established herein do not convert a failure of a public utility transmission provider to comply with a Public Policy Requirement established under state law into a violation of its OATT.

214. We do not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations or to specify additional public policy principles or public policy objectives as some commenters have suggested. Based on the record before us, we believe it is sufficient to ensure just and reasonable rates and to avoid the potential for undue discrimination to restrict the requirement for public policy consideration to state or federal laws or regulations that drive transmission needs. Likewise, we will not require restrictions on the type or number of Public Policy Requirements to be considered as long as any such requirements arise from state or federal laws or regulations that drive transmission needs and as long as the requirements of the procedures required herein are met.

215. Some commenters request that we specify EPA regulations or FPA section 217 as Public Policy Requirements driving potential transmission needs relevant for consideration in the transmission planning process. While we decline to mandate the consideration of transmission needs driven by any *particular* Public Policy Requirement, we intend that the procedures required above be flexible enough to allow for stakeholders to suggest consideration of transmissions needs driven by any Public Policy Requirement, including potential consideration of requirements under EPA regulations, FPA section 217, or any other federal or state law or regulation that drive transmission needs. Because we are not mandating the consideration of any particular transmission need driven by a Public Policy Requirement, we disagree with PSEG Companies that we are favoring renewable energy resources over other types of resources.

216. We reiterate here and clarify a statement of the Proposed Rule that generated significant comment; that is, this Final Rule does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by

[190] To the extent a public utility transmission provider determines that existing provisions of its OATT must be amended in order to implement its evaluation process, it may include such tariff revisions in its compliance filing. For example, evaluation of transmission needs driven by a particular Public Policy Requirement could require the gathering of additional information from interconnected generators regarding retirements or from network customers regarding resource preferences.

[191] This requirement is consistent with the existing requirements of Order Nos. 890 and 890–A which permit sponsors of transmission and non-transmission solutions to propose alternatives to identified needs. *See supra* note 149.

[192] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

state or federal laws or regulations.[193] By providing this clarification, we are neither affirmatively granting new rights to nor imposing an obligation on a public utility transmission provider. Instead, the statement is a recognition that a public utility transmission provider has, and has always had, the ability to plan for any transmission system needs that it foresees. Our recognition of this ability is not intended to limit or expand in any way the option that a public utility transmission provider has always had to plan for facilities that it believes are needed if it chooses to do so. We believe that public utility transmission providers, in consultation with stakeholders, are in the best position to determine whether to consider in a transmission planning process any public policy objectives beyond those required by this Final Rule. We reiterate that this Final Rule creates no obligation for any public utility transmission provider or its transmission planning processes to consider transmission needs driven by a public policy objective that is not specifically required by state or federal laws or regulations. If public utility transmission providers, in consultation with stakeholders, do identify public policy objectives not specifically required by state or federal laws or regulations, we note that transmission facilities designed to meet these objectives may be eligible for cost allocation under the transmission planning process.

217. We note that identifying a set of transmission needs and projects for inclusion in a transmission planning study does not ensure that any particular transmission project will be in the regional transmission plan. Alternative solutions to the identified needs may prove better from cost, siting, or other perspectives. Similarly, elimination of a transmission project or need from the transmission planning process would not prevent any planner or developer from independently seeking to satisfy the need or develop the transmission project, but any resulting transmission facility would not be eligible for cost allocation under a regional cost allocation method or methods required under this Final Rule.

218. Some commenters have expressed concerns that the consideration of transmission needs driven by Public Policy Requirements in the transmission planning process will result in costs being assigned to regions that do not benefit from those requirements or to regions that did not create the need for new transmission. We understand these commenters to be concerned that a requirement to consider transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes will result in cross-subsidization of the costs of meeting Public Policy Requirements.

219. We clarify that any such consideration of transmission needs driven by Public Policy Requirements, to the extent that it results in new transmission costs, must follow the cost allocation principles discussed separately herein.[194] Particularly, the costs of new transmission facilities allocated within the planning region must be allocated within the region in a manner that is at least roughly commensurate with estimated benefits.[195] Those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities. That is, a utility or other entity that receives 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 facilities.

220. Further, we are not requiring that a separate class of transmission projects be created in the transmission planning process related to compliance with Public Policy Requirements, although nothing in this Final Rule prohibits the development of a separate class of transmission projects if the public utility transmission provider and its stakeholders believe that it is appropriate to do so. Some public utility transmission providers might comply with this Final Rule by implementing procedures to consider transmission needs driven by Public Policy Requirements separately from transmission addressing reliability needs or economic considerations. Other public utility transmission providers might comply with this Final Rule by identifying and evaluating all transmission needs, whether driven by Public Policy Requirements, compliance with reliability criteria, or economic considerations. While we provide flexibility for public utility transmission providers to develop procedures appropriate for their local and regional transmission planning processes, we reiterate that all stakeholders must be provided an opportunity to provide input during the identification of transmission needs driven by Public Policy Requirements and the evaluation of potential solutions to the identified needs, as discussed above.

221. In response to Northern Tier Transmission Group, we understand that a public utility transmission provider with a native load obligation may already have addressed compliance with Public Policy Requirements in developing its resource assumptions to be used in the transmission planning process. In such circumstances, the procedures used to identify transmission needs driven by Public Policy Requirements should take that into account. Similarly, the evaluation of potential solutions to those transmission needs identified in a local or regional transmission planning process should reflect the resource decisions of the transmission planning process.

222. The Proposed Rule stated that, if a public utility transmission provider believes that its existing transmission planning process already meets the requirements to consider Public Policy Requirements, then it may make that demonstration in compliance with the Final Rule.[196] Certain commenters question the need for these requirements altogether because they assert they are already obligated to follow all state or federal laws or regulations, including laws or regulations related to public policy objectives. Other commenters, particularly those in ISO and RTO regions, assert that the transmission planning processes administered by those entities already address public policy issues so their compliance obligation should be minimal. In this Final Rule, the Commission is expanding the requirements of the *pro forma* OATT to require that transmission planning processes affirmatively consider transmission needs driven by Public Policy Requirements. Each public utility transmission provider will have the opportunity to demonstrate compliance with these requirements by specifying the procedures in its local and regional transmission planning processes, whether existing or new, for identifying transmission needs driven by Public Policy Requirements and for evaluating potential solutions to meet those identified needs. As with other requirements of this Final Rule, we

[193] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 64. For example, a public utility transmission provider and its stakeholders are not precluded under this Final Rule from choosing to plan for state public policy goals that have not yet been codified into state law, which they nonetheless consider to be important long-term planning considerations.

[194] *See* discussion *infra* section IV.

[195] *See* discussion *infra* section IV.E.2.

[196] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 66.

decline here to prejudge any compliance filings or predetermine whether any public utility transmission provider may already be in compliance.

223. Finally, we considered the many comments on whether it is more appropriate to use flexible criteria in lieu of ''bright line'' metrics when determining which transmission projects are in the regional transmission plan. While we have in the past required adoption of a formulaic approach to applying such metrics,[197] we sought comment on this issue in the Proposed Rule to gain insight as to whether such a formulaic approach was appropriate or if providing additional flexibility was a more effective approach. Our review of the comments suggests that most commenters prefer flexible planning criteria for identifying transmission needs not only driven by Public Policy Requirements and evaluation of solutions to those identified needs, but also for the identification and evaluation of transmission needs related to reliability issues and economic considerations as well.[198] These commenters have convinced us that, although there are benefits to each kind of planning criteria, there is merit in allowing for flexible planning criteria to mitigate the possibility that bright line metrics may exclude certain transmission projects from long-term transmission planning.

224. Hence, we will permit public utility transmission providers to include within their compliance filings in response to this Final Rule any tariff revisions they believe necessary to implement flexible transmission planning criteria, including changes to existing bright line criteria. This could include procedures to address alternating inclusion and exclusion of a single transmission project in a regional transmission plan over successive planning cycles. Because such tariff revisions will be included as part of the compliance filings in response to this Final Rule, they will be submitted pursuant to section 206 of the FPA rather than under section 205. However, those with existing bright line criteria are not required to make this change if they do not wish to do so. As we evaluate the compliance filings to this Final Rule, we also will evaluate both bright line and flexible criteria for whether they permit unjust and unreasonable rates or undue discrimination through planning criteria and whether they will ensure fair consideration of transmission needs driven by Public Policy Requirements as well as by reliability needs and economic considerations.

B. Nonincumbent Transmission Developers

225. This part of the Final Rule addresses the removal from Commission-jurisdictional tariffs and agreements of provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. To implement the elimination of such rights, we adopt below a framework that requires the development of qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated in the regional transmission planning process. We further require that any nonincumbent developer of a transmission facility selected in the regional transmission plan have an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. For purposes of this Final Rule, ''nonincumbent transmission developer'' refers to two categories of transmission developer: (1) A transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, and as we explained in the Proposed Rule, an ''incumbent transmission developer/provider'' is an entity that develops a transmission project within its own retail distribution service territory or footprint.[199]

226. We conclude these reforms are necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable, or otherwise result in undue discrimination by public utility transmission providers. As discussed in detail below, our focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation, and not on transmission facilities included in local transmission plans that are merely ''rolled up'' and listed in a regional transmission plan without going through a needs analysis at the regional level (and therefore, not eligible for regional cost allocation). Similarly, our reforms are not intended to affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, nor to alter an incumbent transmission provider's use and control of an existing right of way.

227. In developing the framework below, we have sought to provide flexibility for public utility transmission providers in each region to propose, in consultation with stakeholders, how best to address participation by nonincumbents as a result of removal of the federal right of first refusal from Commission-jurisdictional tariffs and agreements. However, we note that nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. Public utility transmission providers must establish this framework in consultation with stakeholders and we encourage stakeholders to fully participate.

1. Need for Reform Concerning Nonincumbent Transmission Developers

a. Commission Proposal

228. As discussed above, Order No. 890 sought to reduce opportunities for undue discrimination and preference in the provision of transmission service. With regard to the transmission planning process, the Commission established nine transmission planning principles to prevent undue discrimination. However, Order No. 890 did not specifically address the potential for, or effect of, undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes. The Commission observed in the October 2009 Notice[200] that, as a result of existing practices in some areas, a nonincumbent transmission developer may lose the opportunity to construct its proposed transmission project to the incumbent transmission owner if that owner has a federal right of first refusal to construct any transmission facility in

[197] *See, e.g., PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 (2007).

[198] *E.g.,* AWEA; PJM; New York ISO; SPP; WECC; and Westar.

[199] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.23.

[200] Federal Energy Regulatory Commission, Notice of Request for Comments; Transmission Planning Processes under Order No. 890; Docket No. AD09–8–000, October 8, 2009 (October 2009 Notice).

its service territory. The October 2009 Notice sought comment whether such a federal right of first refusal for incumbent transmission owners unreasonably impedes the development of merchant and independent transmission and, if so, how that impediment could be addressed.

229. Based on the comments received, the Commission determined that if a regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents that regional transmission planning process cannot meet the Order No. 890 transmission planning principle of being ''open.'' Moreover, the Commission stated that such regional planning process may not result in a cost-effective solution to regional transmission needs, and transmission projects in a regional transmission plan therefore may be developed at a higher cost than necessary.[201] As a result, regional transmission services may be provided at rates, terms and conditions that are not just and reasonable. In addition, the Commission determined in the Proposed Rule that there appeared to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission explained that, where an incumbent transmission owner has a federal right of first refusal, a nonincumbent transmission developer risks losing its investment to develop a transmission project that it proposed in the regional transmission planning process, even if the transmission project that the nonincumbent transmission developer proposed is in a regional transmission plan. The Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process under these circumstances.

230. To address these issues, the Commission proposed to reform provisions in public utility transmission providers' OATTs or other agreements subject to the Commission's jurisdiction that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities that are in a regional transmission plan.

b. Comments

231. A number of commenters support the Commission's proposal to address federal rights of first refusal in Commission-jurisdictional tariffs and agreements.[202] For example, Federal Trade Commission states that the existence of a federal right of first refusal in jurisdictional tariffs and agreements reduces capital investment opportunities for potential nonincumbent developers by increasing their risk, encourages free ridership among incumbent developers, and creates a barrier to entry. A number of state utility commissions and consumer advocates agree, arguing that such provisions impede transmission development and that removing the provisions would provide a level playing field for incumbent and nonincumbent transmission developers.[203]

232. For example, California Department of Water Resources states that competition among transmission providers that promotes efficiencies and innovation should be supported in regulatory policy and transmission planning. New Jersey Board, Connecticut & Rhode Island Commissions and Massachusetts Departments support the proposal to remove a federal right of first refusal, also stating that competition among project sponsors will result in lower cost approaches to meeting system needs. They caution, however, that equal rights must be followed by equal responsibilities and obligations at the federal, regional, state and local level. New England States Committee on Electricity contends that increased competition about which entity will build transmission facilities could help improve cost controls over time. Pennsylvania PUC supports the proposal to eliminate undue discrimination against nonincumbent transmission developers and the attempt to eliminate some of the barriers to full participation by nonincumbent transmission developers. Pennsylvania PUC cautions the Commission, however, to continue to respect Pennsylvania PUC's statutory responsibility to review and approve the siting of transmission projects located in Pennsylvania. Ohio Commission agrees that eliminating rights of first refusal has merit to the extent that parameters are established to ensure that ratepayers see cost savings and enhanced reliability. Ohio Consumers' Counsel and West Virginia Consumer Advocate Counsel state that eliminating barriers to participation can encourage additional transmission development that could be constructed at lower cost to consumers. Arizona Corporation Commission supports the removal of rights of first refusal, but states that it does not see this as having an impact on an incumbent utility's obligations to serve or affecting the transmission planning process currently utilized in Arizona.

233. Some commenters representing transmission-dependent and municipal utilities express support for the Commission's proposal.[204] Transmission Dependent Utility Systems state that a right of first refusal can prevent or delay construction of needed transmission facilities proposed by nonincumbent transmission developers and also can be used to block transmission access for generation resources that are not associated with the incumbent transmission provider. Northern California Power Agency states that any entity, whether an investor-owned utility, municipal entity, or independent developer, should have the right to propose, construct, and own transmission projects, subject to minimum safety and reliability requirements. Eastern Massachusetts Consumer-Owned System states that eliminating the right of first refusal should help open the door to municipal utility participation in transmission ownership on a larger scale.

234. Others supporting the proposal include entities representing independent developers of transmission and generation.[205] NextEra states that allowing the right of first refusal to continue would impede development of innovative transmission solutions in that a transmission project is unlikely to advance very far if its developer cannot

[201] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87–88.

[202] *E.g.,* Federal Trade Commission; American Antitrust Institute; Ohio Consumers' Counsel and West Virginia Consumer Advocate Division; American Forest & Paper; DC Energy; Elmer John Tompkins; EIF Management; 26 Public Interest Organizations; and Boundless Energy; Pennsylvania PUC; Connecticut & Rhode Island Commissions; Northern California Power Agency; Eastern Massachusetts Consumer-Owned System; and Transmission Dependent Utility Systems; Arizona Corporation Commission; New Jersey Board; and California PUC; NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

[203] *E.g.,* Arizona Corporation Commission; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New Jersey Board; Massachusetts Departments; Ohio Consumer's Counsel; Pennsylvania PUC; and West Virginia Consumer Advocate.

[204] *E.g.,* Eastern Massachusetts Consumer-Owned System; Northern California Power Agency; Transmission Agency of Northern California; and Transmission Dependent Utility Systems.

[205] *E.g.,* NextEra; AWEA; Anbaric and PowerBridge; Clean Line; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; FirstWind; Green Energy and 21st Century; Colorado Independent Energy Association; Enbridge; Primary Power; and Western Independent Transmission Group.

be confident that it can see the transmission project to its completion. Clean Line supports the elimination of the right of first refusal and states that encouraging the participation of nonincumbent transmission developers in the regional transmission planning process would increase competition and expand development, which can ultimately lead to lower costs for ratepayers. LS Power states that a right of first refusal and all other discriminatory rules should be eliminated from transmission planning processes inside and outside of RTOs and ISOs.[206] Pattern Transmission states that rights of first refusal and similar preferences favoring incumbent transmission owners do not result in transmission rates that are just and reasonable, are inherently preferential and unduly discriminatory, and suggests that the right of first refusal allows incumbent transmission owners to engage in gaming. Primary Power contends that removing a right of first refusal from all Commission-jurisdictional tariffs and agreements would provide an opportunity for a wider variety of technical and financial resources to participate in transmission infrastructure development. Western Independent Transmission Group contends that the ability of incumbent transmission owners to construct transmission projects proposed by other transmission developers under a right of first refusal is equivalent to the seizure of intellectual property.

235. Some commenters cite to examples that they believe show the benefits of removing barriers to competition by nonincumbent transmission developers. For example, Western Independent Transmission Group points to the success of Texas's Competitive Renewable Energy Zone planning process in supporting transmission development by nonincumbent developers. Also, Western Independent Transmission Group points to the Trans Bay Cable, Neptune, and Cross Sound Cable transmission projects, which were developed by nonincumbent transmission developers. Pattern Transmission cites the benefits associated with increased competition in the telecommunications and railroad industries, arguing that comparable benefits are available in the electric industry.

236. Some commenters supporting the Commission proposal argue that the record in this proceeding is sufficient to support taking action at this time. Primary Power states that Commission is ''not required to make specific findings so long as the agency's factual determinations are reasonable.'' [207] LS Power states that the Commission has legal authority to address discrimination against prospective transmission owners, it has a substantial record that rights of first refusal are unreasonable and result in undue discrimination, thus satisfying the *National Fuel* standard.

237. Commenters supporting the Proposed Rule generally contend that the elimination of rights of first refusal in Commission-jurisdictional tariffs and agreements would not be in conflict with the responsibilities of incumbent transmission providers, such as the obligation imposed under RTO and ISO membership agreements to build transmission facilities identified as needed in regional transmission plans.[208] These commenters state that, to the extent that an incumbent transmission owner feels unreasonably burdened by its obligations to build, a nonincumbent transmission developer would welcome the opportunity to respond to competitive solicitations to build the obligatory transmission projects. Such commenters further note that, as independent transmission developers build transmission projects and become transmission owners themselves, they also may be subject to appropriate obligations to build adjacent or connecting transmission facilities. Northwest & Intermountain Power Producers Coalition states that an incumbent's service obligation would come into play only if no alternative proposal is available to meet the identified need and that, where better alternatives are identified in the planning process, there is no good reason to prevent the better alternative from being constructed merely because the incumbent has an obligation to construct where a better alternative does not exist. Western Independent Transmission Group suggests that the obligation to build is a benefit, not a burden, because an incumbent transmission developer that constructs a transmission project pursuant to an obligation will receive full cost-of-service recovery, including a fair rate of return on its investment.

238. Others urge the Commission to provide thoughtful consideration to the potential impacts of its proposal.[209] Energy Future Coalition states that, while a right of first refusal should not give incumbent utilities the ability to block or stall construction of needed infrastructure within their service territories, or to inflate the costs of such projects, transmission goals will be frustrated if elimination of such provisions bogs down the transmission planning process. New England Transmission Owners state that, before taking action to eliminate any right of first refusal, the Commission should consider the unique way in which transmission projects are identified for development, the success of the current planning process, and the unique characteristics of the New England system that make the current process appropriate for this region. National Rural Electric Coops suggest that, prior to proceeding with the proposed reforms, the Commission consider adoption of principles to allow load-serving entities to participate in projects developed by traditional and independent transmission providers and to have the right to acquire an ownership participation in any project that it built within their service territories.

239. A number of commenters oppose any alteration of rights of first refusal in Commission-jurisdictional tariffs and agreements, arguing that there is insufficient evidence to justify removal of the right of first refusal.[210] Edison Electric Institute states that, on the contrary, there has been substantial evidence submitted to the Commission that a right of first refusal benefits consumers and results in lower rates, evidence that the Commission has not sought to rebut. Southern California Edison alleges that the Commission provides nothing more than speculative and vague statements that a right of first refusal may preclude nonincumbent transmission developers from participating in the regional transmission planning process and, in turn, affect rates for transmission service. ITC Companies contend that a right of first refusal is not the primary barrier to new market entrants and that they see no impediment to

[206] LS Power citing *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (*reh'g pending*); *Central Transmission, LLC* v. *PJM Interconnection L.L.C.*, 131 FERC ¶ 61,243 (2010).

[207] Primary Power cites to *Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667, 688 (DC Cir. 2000).

[208] *E.g.*, Anbaric and PowerBridge; Green Energy and 21st Century; LS Power; Northwest & Intermountain Power Producers Coalition; Pattern Transmission; Primary Power; Transmission Agency of Northern California; and Western Independent Transmission Group.

[209] *E.g.*, Energy Future Coalition; New England Transmission Owners; and MidAmerican.

[210] *E.g.*, California ISO; SPP; CapX2020 Utilities; Edison Electric Institute; Southern California Edison; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; PSEG Companies Comments; and San Diego Gas & Electric.

nonincumbent transmission developers pursuing development opportunities through a partnership model whereby right of first refusal rights are delegated. Oklahoma Gas & Electric notes that a number of transmission-only companies have announced significant transmission projects in SPP and, joined by MISO Transmission Owners, argues that it is premature for the Commission to determine that further reforms are needed to further encourage development.

240. Citing *National Fuel*,[211] some commenters argue that the Commission points to no evidence of actual discrimination or adverse impact on rates and that it must identify something more than theoretical possibilities to justify elimination of federal rights of first refusal.[212] Indicated PJM Transmission Owners assert that, if the Commission intends to rely solely on the effects of potential discrimination, in the absence of evidence of abuse, it must explain why the historical right of incumbent transmission owners to construct additions in their service territories so endangers open access to transmission service at just and reasonable rates as to justify a complete rearrangement of the relationship between public utilities, state regulators, and ultimate customers. MISO Transmission Owners state that the Proposed Rule fails to demonstrate why the existing complaint procedures under section 206 do not protect third parties from such theoretical harm.

241. Many of these commenters argue that preserving a federal right of incumbent transmission owners to build within their service territories is the best method to achieve the Commission's overall transmission goals. Such commenters contend that incumbent transmission owners are better situated to build new transmission facilities.[213] For example, Oklahoma Gas & Electric argues that incumbent transmission owners are often in the best position to determine where new transmission is needed on their system. CapX2020 Utilities and MidAmerican state that load serving transmission providers have a long history and relationship with state regulatory bodies that brings value to getting needed transmission developed. Ad Hoc Coalition of Southeastern Utilities and Southern Companies contend that incumbent transmission owners are better situated to obtain any necessary approval from state regulators to recover the cost of transmission facilities through bundled retail tariffs and that nonincumbent developers may have no obligation or ability to do so, depriving the state of an opportunity to determine that the proposal is the most reliable and cost-effective alternative. Ad Hoc Coalition of Southern Utilities adds that a nonincumbent developer's lack of a funding mechanism based on retail rates is a function of the state-based ratemaking process, not a preference for incumbent transmission owners.

242. Other commenters question the potential impact removal of a federal right of first refusal may have on transmission rates.[214] North Dakota & South Dakota Commissions argue that there is no evidence to suggest that nonincumbents are better situated to provide lower cost or more reliable service, and note that nonincumbents are not regulated by state commissions and not subject to state law obligations regarding reliability or state law oversight of their operations. Alabama PSC states concern that the proposed elimination of the incumbent's federal right of first refusal could increase costs to Alabama consumers. Edison Electric Institute argues that the Commission's proposal ignores longstanding policy that a public utility's investment is assumed to be prudent when a range of options are available, arguing that the Proposed Rule would have a reasonable rate depend upon the identity of the builder of the transmission facility.

243. Some commenters argue that any lower costs that result from competition to own and construct transmission projects is likely to be more than offset by inefficiencies created in the transmission planning process and a loss of economies of scale and scope.[215] Pacific Gas & Electric states that competition may have cost impacts to incumbent transmission owners relating to their obligation to maintain or improve reliability and security of the existing transmission system to comply with current and future reliability standards. Southern Companies contend that consumers bear the risk of nonincumbent developers declaring bankruptcy or becoming unable or unwilling to complete a transmission project, suggesting that the Commission require ''step in'' rights in such circumstances to facilitate an incumbent transmission owner's assumption of the project, should it voluntarily choose to do so. Transmission Dependent Utility Systems state that the proposal could raise costs by causing customers outside of an RTO/ISO region to pay both the full costs of the incumbent transmission provider's transmission system and the full incremental costs of any nonincumbent transmission projects necessary to serve its load.

244. Indicated PJM Transmission Owners assert that, even if a nonincumbent were to propose a less expensive transmission project for recovery through cost-based rates, there is no assurance that its final costs will be equal to or lesser than its estimate, or that it has a greater likelihood of staying within its cost estimate than an incumbent transmission owner. They contend that the Commission misapplies cost-effectiveness principles to non-rate matters beyond its authority, without factual or logical support. PPL Companies agree, arguing that consumers will bear the risk of cost overruns by nonincumbent transmission developers. California ISO notes that the Trans Bay Cable, cited by Western Independent Transmission Group, had significant cost overruns, and that the Neptune and Cross Sound Cable transmission projects were merchant transmission projects that, as direct current transmission lines, involved fewer concerns about system compartmentalization and fragmentation. Southern California Edison states that under the Proposed Rule, there does not appear to be any incentive for project participants to develop cost-efficient proposals because it is not clear if and how customer costs would be considered in project selection.

245. Several comments suggest that the proposal is based on a false assumption that providing for greater competition in the provision of transmission development will produce benefits to consumers.[216] They state that unlike generation, a competitive model cannot be adopted for wholesale transmission because customers have no meaningful alternative transmission provider and the development cycle for transmission is much longer than for

[211] *National Fuel*, 468 F.3d 831.

[212] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Indicated PJM Transmission Owners; Large Public Power Council; MidAmerican; MISO Transmission Owners; Oklahoma Gas & Electric; PSEG Companies; Salt River Project; and San Diego Gas & Electric. Large Public Power Council also cites to *Associated Gas Distributors.*

[213] *E.g.*, PJM; CapX2020 Utilities; Edison Electric Institute; Georgia Transmission Corporation; MidAmerican; Omaha Public Power District; Pacific Gas & Electric; Sunflower and Mid-Kansas; and Transmission Access Policy Study Group.

[214] *E.g.*, Alabama PSC; City of Santa Clara; Dominion; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; PSEG Companies; Southern California Edison; Sunflower and Mid-Kansas; and Xcel.

[215] *E.g.*, Dominion; PSEG Companies; North Dakota & South Dakota Commissions; and Oklahoma Gas & Electric Company.

[216] *E.g.*, California ISO; Indianapolis Power & Light; Oklahoma Gas & Electric Company; and Pacific Gas & Electric.

generation. California ISO disagrees that the benefits of competition cited by Western Independent Transmission Group and Pattern Transmission are relevant to its transmission planning process. PPL Companies similarly argues that commenters arguing that eliminating the right of first refusal benefits competition misunderstand the nature of the transmission planning process, noting that RTO planning processes do not involve price competition or consumer choice. PPL Companies contend that eliminating the right of first refusal would not add choice for consumers since the transmission projects included in RTO plans are driven by needs, and not by proposals from incumbent or nonincumbent developers.

246. A number of commenters assert that removing a federal right of first refusal would complicate and undermine the transmission planning process.[217] Delaware PSC states that the Proposed Rule would fundamentally change the way transmission facilities are proposed, selected, and built, and requires thoughtful consideration of all its implications. MISO states that placing regional planners in a role of deciding who should build introduces a level of financial competition to the planning process that is fundamentally at odds with the high level of openness and collaboration under the current approach. Kansas City Power & Light and KCP&L Greater Missouri contend that the proposal would exacerbate an already complex and arduous process to study, plan and implement regional transmission infrastructure. Dominion states that eliminating a federal right of first refusal would create a model where competitively sensitive information will be withheld from open discussion, thus making the planning process less collaborative. Xcel agrees that the proposal could harm the planning process and that disagreements about transmission project selection could have negative impacts on state-level siting and routing approval processes.

247. Some commenters caution that implementation of the proposed reforms could have unintended consequences affecting reliability.[218] These commenters generally contend that eliminating federal rights of first refusal could cause, or exacerbate, operational and reliability challenges for transmission system operations and could produce operational issues as each transmission provider will have to coordinate with more entities to address specific reliability issues. Many of these commenters contend that increasing the number of entities involved in transmission ownership and grid operations would make coordination, maintenance, and service restoration more difficult by further fragmenting the transmission system, which they note has been a concern of the Commission in the past.

248. Several commenters contend that the right of first refusal is inextricably linked to the obligation to build imposed under RTO and ISO membership agreements, justifying any difference in treatment between incumbent transmission owners and nonincumbent transmission developers.[219] These commenters generally argue that retention of an obligation to build without a corresponding right of first refusal would impose a serious and unjust and unreasonable burden on incumbent transmission owners and is in violation of the FPA. Some state commissions express concern that the Commission's proposal may undermine the ability of utilities to meet their load service obligations.[220] Other commenters state that it is important to maintain an obligation to build for its transmission owning members to ensure transmission projects needed for reliability can be developed promptly.[221] Some commenters contend that the Commission's proposed reforms would result in undue discrimination against incumbent utilities, giving nonincumbent transmission developers the opportunity to propose and build a transmission facility, whereas incumbents would be required to build any needed transmission facility, including those that may be abandoned or not completed by the nonincumbent developer.[222] Many of these commenters contend this would permit nonincumbent transmission developers to ''cherry pick'' only the most advantageous projects in terms of financial reward and development risk.[223] Southern California Edison contends that the Commission's proposal amounts to establishing a free call on a utility's capital without any return to compensate it for the time period in which that capital had to be held in reserve to meet a backstop obligation to build.

249. Several commenters express concern about the impact that removing a federal right of first refusal in Commission-jurisdictional tariffs and agreements may have on RTO and ISO participation.[224] For example, MISO states that the right of its transmission owner members to build transmission facilities identified through the planning process was, and remains, one of the key considerations for its transmission owners to have formed, and to remain a part of, the voluntary RTO. MISO Transmission Owners argue that the Proposed Rule would result in undue discrimination between transmission owners voluntarily participating in RTOs and transmission owners that have not joined an RTO. MISO Transmission Owners state that, without a right to construct new transmission facilities within their own systems, a transmission owner could experience substantial erosion of its revenues over time as a result of RTO participation. MISO Transmission Owners add that construction obligations and rights in RTOs and ISOs have been carefully designed to ensure that RTOs, ISOs, and their members can comply with all applicable state and federal service obligations and reliability standards. Southern Companies state that the Commission should clarify that the reforms relating to nonincumbent transmission developers do not apply in non-RTO regions. On the other hand, Transmission Agency of Northern California emphasizes that the Commission's proposal to remove a right of first refusal from all Commission-approved tariffs and agreements should apply in both non-RTO/ISO and RTO/ISO regions.

[217] *E.g.*, AEP; Allegheny Energy Companies; Baltimore Gas & Electric; Dominion; Edison Electric Institute; First Energy Service Company; Indianapolis Power & Light; Kansas City Power & Light and KCP&L Greater Missouri; MidAmerican; MISO; MISO Transmission Owners; Pacific Gas & Electric; and Southern California Edison.

[218] *E.g.*, Baltimore Gas & Electric; California ISO; Edison Electric Institute; MidAmerican; Oklahoma Gas & Electric; Pacific Gas & Electric; PJM; PSEG Companies; Southern California Edison; and Xcel.

[219] *E.g.*, ISO New England; PJM; SPP; Federal Trade Commission; SPP; MISO Transmission Owners; Edison Electric Institute; Georgia Transmission Corporation; Indianapolis Power & Light; Large Public Power Council; Nebraska Public Power District; Arizona Public Service Company; Oklahoma Gas & Electric; MidAmerican; PSEG Companies; San Diego Gas & Electric; Southern California Edison; Tucson Electric; Xcel; Allegheny Energy Companies; Duke; Baltimore Gas & Electric; Dominion; E.ON; Exelon; Westar Integrys; and FirstEnergy Service Company.

[220] *E.g.*, Florida PSC; Minnesota PUC; and Minnesota Office of Energy Security.

[221] *E.g.*, ISO New England; MidAmerican; and MISO Transmission Owners.

[222] *E.g.*, Baltimore Gas & Electric; Edison Electric Institute; FirstEnergy Service Company; Large Public Power Council; MidAmerican; MISO Transmission Owners; PPL Companies; PSEG Companies; and Xcel.

[223] *E.g.*, Baltimore Gas & Electric; California ISO; CapX2020 Utilities; Indianapolis Power & Light; Oklahoma Gas & Electric; Southern California Edison; and Xcel.

[224] *E.g.*, MISO; MISO Transmission Owners; Edison Electric Institute; Alliant Energy; MidAmerican; and Indianapolis Power & Light.

250. Some commenters argue that the existence of native load and state franchise obligations further distinguish incumbent transmission owners from nonincumbent transmission developers, justifying retention of federal rights of first refusal.[225] These commenters assert that nonincumbent developers are not similarly situated because they can select the transmission projects they wish to pursue and ignore those they deem too risky or insufficiently profitable, unencumbered by a ''duty to serve'' requiring the construction and maintenance of facilities necessary to render reliable, cost-effective service to customers in their service territories. For example, Baltimore Gas & Electric states that it and others view their licensed obligations to protect their service territory from power outages as being paramount over their mere financial interests. Edison Electric Institute and MISO Transmission Owners argue that differing state law obligations have been found to be legitimate factors in determining that two entities are not similarly situated.[226] San Diego Gas & Electric contends that removal of federal rights of first refusal raises constitutional concerns since, as regulated entities, public utility transmission providers are entitled under well-established law to receive a reasonable rate of return on their investment in transmission infrastructure in discharging their state-mandated service obligations.[227]

251. A number of commenters suggest that the Commission consider partial elimination of federal rights of refusal.[228] Many of these commenters endorse SPP's current mechanism, under which an incumbent utility has a 90-day time limit to exercise its right to construct a facility included in the regional transmission plan. AEP suggests that the Commission consider a phased approach, beginning with a time limit on the exercise of any right of first refusal and, if this does not substantially address the Commission's concerns, then consider further modification or elimination of the right of first refusal. AEP suggests that the Commission also could require each region to report back to the Commission within two years on its experience implementing the time-limited right of first refusal as a basis for the Commission to consider whether a fundamental change of the existing regional transmission planning process is needed. California PUC and Exelon argue that incumbent transmission owners should maintain the right of first refusal for reliability projects located within a single zone. Transmission Access Policy Study Group recommends that the Commission retain a limited right of first refusal that can be exercised only when the incumbent transmission provider forgoes transmission incentives for the project and offers meaningful joint ownership opportunities on reasonable terms. Other commenters disagree with proposals to maintain limited rights of first refusal, generally arguing that such proposals would perpetuate the entry barrier.[229]

252. Finally, some commenters suggest that the Commission engage in additional outreach on this issue before altering federal rights of first refusal.[230] They encourage the Commission to host a technical conference or initiate other proceedings so that all of these issues can be examined and potential solutions developed in a collaborative manner. Sunflower and Mid-Kansas contend that, if problems relating to a right of first refusal exist in a particular region, the issue should be addressed locally rather than imposing a one-size-fits-all solution across all regions.

c. Commission Determination

253. The Commission concludes that there is a need to act at this time to remove provisions from Commission-jurisdictional tariffs and agreements that grant incumbent transmission providers a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation.[231] Failure to do so would leave in place practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers. The Commission addresses the need for eliminating such practices in this section and, in the sections that follow, our legal authority to do so and the procedures by which public utility transmission providers must implement the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

254. As the Commission recognized in Order Nos. 888 and 890, it is not in the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply.[232] In Order No. 890, the Commission required greater coordination in transmission planning on a regional level to remedy the potential for undue discrimination by transmission providers that have an incentive to avoid upgrading transmission capacity with interconnected neighbors where doing so would allow competing suppliers to serve the customers of the public utility transmission provider.[233] Although basing its actions on its authority to remedy undue discrimination, the Commission found that ''[t]he coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.'' [234]

255. In response to Order No. 890, regions across the country have implemented transmission planning processes that allow for consideration of alternative transmission projects proposed at the regional level to determine if they better meet the

[225] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Edison Electric Institute; Large Public Power Council; MISO Transmission Owners; Nebraska Public Power District; Xcel; PPL Companies; and Xcel. In support, Ad Hoc Coalition of Southeastern Utilities cites to *California Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 369 (2007); *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, at P 36 (2006); and *Sebring Utils. Comm'n* v. *FERC*, 591 F.2d 1003, 1009 n.24 (5th Cir. 1979). MISO Transmission Owners also cite to *S. Cal. Edison Co.*, 59 FPC 2167, 2185–86 (1977).

[226] Edison Electric Institute and MISO Transmission Owners cite to *Town of Norwood* v. *FERC*, 202 F.3d 392, 403 (1st Cir. 2000).

[227] San Diego Gas & Electric supports these assertions by citing *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works* v. *Public Serv. Comm'n*, 262 U.S. 679 (1923).

[228] *E.g.,* California PUC; Transmission Dependent Utility Systems; SPP; AEP; Iberdrola Renewables; Indianapolis Power & Light; ITC Companies; MidAmerican; Oklahoma Gas & Electric; Southern California Edison; Westar; Xcel; CapX2020 Utilities; and SPP.

[229] *E.g.,* American Antitrust Institute; Anbaric and PowerBridge; LS Power; NextEra; Pattern Transmission; and Western Independent Transmission Group.

[230] *E.g.,* Delaware PSC; NextEra; San Diego Gas & Electric; and Tucson Electric.

[231] As explained in more detail in section III.B.3 below, the Commission purposely refers to ''federal rights of first refusal'' in this Final Rule because the Commission's action on this issue in this Final Rule addresses only rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. This Final Rule does not require removal of references to such state or local laws or regulations from Commission-approved tariffs or agreements.

[232] Order No. 888, FERC Stats. & Regs. at 31,682; Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[233] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[234] *Id.*

region's needs.[235] The evaluation of alternative transmission solutions at the regional level is often referred to as ''top down'' planning.[236] In some regions, heavy emphasis is placed on ''top down'' regional planning for all or certain classes of transmission facilities. In other regions, local transmission plans are developed in which individual public utility transmission providers within the region identify solutions to their own local needs prior to the ''top down'' consideration of regional alternatives. This is often referred to as ''bottom up, top down'' planning.[237] Although the relative weight placed on ''bottom up'' or ''top down'' processes varies by region, all of these existing processes allow at some point for transmission project developers to offer alternative solutions for evaluation on a comparable basis pursuant to criteria that is set forth in the public utility transmission providers' OATTs.[238] By requiring the comparable evaluation of all potential transmission solutions, the Commission has sought to ensure that the more efficient or cost-effective solutions are in the regional transmission plan.[239]

256. The Commission is concerned that the existence of federal rights of first refusal may be leading to rates for jurisdictional transmission service that are unjust and unreasonable. Allowing federal rights of first refusal to remain in Commission-jurisdictional tariffs and agreements would undermine the consideration of potential transmission solutions proposed at the regional level. Just as it is not in the economic self-interest of public utility transmission providers to expand transmission capacity to allow access to competing suppliers, it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs. We conclude that an incumbent transmission provider's ability to use a right of first refusal to act in its own economic self-interest may discourage new entrants from proposing new transmission projects in the regional transmission planning process.

257. Federal rights of first refusal exacerbate these problems by, as the Federal Trade Commission and other commenters explain, creating a barrier to entry that discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level. Many commenters note that significant investment is needed to support the development of a successful transmission project, yet there is a disincentive for a nonincumbent transmission developer to commit its resources to a potential transmission project when it runs the risk of an incumbent transmission provider exercising its federal right of first refusal once the benefits of the transmission project are demonstrated. The Commission recognizes that removing federal rights of first refusal in Commission-jurisdictional tariffs and agreements will not eliminate all obstacles to transmission development that may exist under state or local laws or regulations and, therefore, may not address all challenges facing nonincumbent transmission development in those jurisdictions. It does not follow, however, that the Commission should leave in place federal rights of first refusal. Moreover, the number of state commission commenters supporting the Commission's proposal indicate that, at a minimum, there is interest in those jurisdictions to explore the benefits of nonincumbent transmission development.

258. The Commission shares the concerns of some commenters that elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, if not implemented properly, could adversely impact the collaborative nature of current regional transmission planning processes. The Commission addresses these concerns in section III.B.3 by modifying and clarifying the proposed framework for implementing our reforms, including elimination of the proposed requirement to allow a transmission developer to maintain for a defined period a right to build and own a transmission facility. In addition, this Final Rule does not require removal of a federal right of first refusal for a local transmission facility, as that term is defined herein.[240] The Commission disagrees with commenters asserting that reforming federal rights of first refusal would fundamentally alter regional transmission planning processes. Public utility transmission providers already are required to evaluate whether alternative transmission solutions proposed by other developers better meet the needs of the region. Therefore, existing regional transmission planning processes have mechanisms in place to weigh various alternatives against one another. Indeed, this is the fundamental nature of ''bottom-up, top-down'' transmission planning, in which local needs and solutions are combined within a region and analyzed to determine whether regional solutions would be more efficient or cost-effective than the local solutions identified by individual public utility transmission providers.[241]

259. The Commission understands that the degree to which existing transmission planning processes will be impacted by the elimination of federal rights of first refusal will vary by region, just as the current mechanisms used to evaluate competing transmission projects vary by region. For example, the public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit projects or project developers to meet regional needs. To the extent a region already has in place processes to rely on market proposals or competitive solicitations when identifying solutions to the region's needs, such existing processes may require relatively modest modifications to provide nonincumbent transmission providers with the opportunity to propose and construct transmission projects, consistent with state and local laws and regulations. In regions relying more heavily on local planning with less robust mechanisms to identify alternative transmission solutions at the regional level, more effort may be needed to implement the Commission's reforms. Within the implementation framework adopted below, the Commission provides each region with the flexibility necessary to identify the modifications to existing transmission planning processes that may be required as a result of removing

[235] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 215–16. Sponsors of generation and demand response solutions are provided comparable opportunities to offer their proposals in the regional transmission planning process. *Id.*

[236] *See, e.g.,* Pacific Gas & Electric Initial Comments describing top down planning.

[237] *See, e.g.,* Large Public Power Council Initial Comments describing bottom up planning.

[238] *See, e.g.,* Entergy OATT, Attachment K at § 3.12; Florida Power and Light OATT, Appendix 1 to Attachment K, §§ H and I; ISO New England OATT, Attachment K at § 4.2; Puget Sound Energy OATT, Attachment K at § 2; SPP OATT, Attachment O at § III.8.

[239] *See, e.g., Northwestern Corp.,* 128 FERC ¶ 61,040, at P 38 (2009); *El Paso Electric Co.,* 128 FERC ¶ 61,063, at P 15 (2009); *New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044, at P 35 (2009).

[240] *See* definition *supra* section II.D of this Final Rule.

[241] Similarly, the Commission believes that concerns regarding the cost-effectiveness of nonincumbent transmission development are misplaced. For one solution to be chosen over another in the transmission planning process, there must be an evaluation of the relative economics and effectiveness of performance for each alternative. *See, e.g., New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044 at P 35, n.26.

federal rights of first refusal from Commission-jurisdictional tariffs and agreements.

260. The Commission is not persuaded to abandon our proposed reforms to federal rights of first refusal based on arguments that incumbent transmission providers are better situated to build and operate transmission facilities. While we acknowledge that incumbent transmission providers may have unique knowledge of their own transmission systems, familiarity with the communities they serve, economies of scale, experience in building and maintaining transmission facilities, and access to funds needed to maintain reliability, we do not believe removing the federal right of first refusal diminishes the importance of these factors. An incumbent public utility transmission provider is free to highlight its strengths to support transmission project(s) in the regional transmission plan, or in bids to undertake transmission projects in regions that choose to use solicitation processes. However, we do not believe that, just because an incumbent public utility transmission provider may have certain strengths, a nonincumbent transmission developer should be categorically excluded from presenting its own strengths in support of its proposals or bids.

261. Various commenters argue that federal rights of first refusal are inextricably tied to obligations to build placed on incumbent transmission providers, such as those under RTO and ISO member agreements. We acknowledge that a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO or ISO, but we do not believe that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region. There are many benefits and obligations associated with membership in an RTO or ISO and an obligation to build at the direction of the RTO or ISO is only one aspect of the agreement. While implementation of reforms to federal rights of first refusal may change the package of benefits and burdens currently in place for transmission owning members of RTOs and ISOs, we find that such changes are necessary to correct practices that may be leading to rates for jurisdictional transmission service that are unjust and unreasonable.

262. Some commenters also contend that the federal right of first refusal is necessary for incumbent transmission providers to develop transmission facilities needed to comply with a reliability standard or an obligation to serve customers. We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint. The Final Rule continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation. Alternatively, an incumbent transmission provider may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation. Our decision today does not prevent an incumbent transmission provider from continuing to propose transmission projects for consideration in the regional transmission planning process and to receive regional cost allocation if those projects are selected in a regional transmission plan for such purposes, even if they are located entirely within its retail distribution service territory or footprint.

263. Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations. To avoid this result, in section III.B.3 below, we require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations.

264. One function of the regional transmission planning process is to identify those transmission facilities that are needed to meet identified needs on a timely basis and, in turn, enable public utility transmission providers to meet their service obligations. Given the familiarity incumbent transmission providers have with their own systems, we expect that they will continue to participate actively in the regional transmission planning process to share their unique perspectives regarding whether various potential solutions meet particular needs of their systems. To the extent an incumbent transmission provider has concerns that a regional transmission alternative does not address the identified reliability needs or service obligations that would allow it to serve its customers reliably to meet state or local laws, whether upon initial evaluation or, as relevant, subsequent reevaluation, it can make such concerns known so that all relevant information regarding a regional transmission alternative can be considered.

265. The Commission disagrees that elimination of federal rights of first refusal would result in discrimination against incumbent transmission providers in favor of nonincumbent transmission developers. Once a member of an RTO or ISO, a nonincumbent transmission developer will be subject to the relevant obligations that apply to the RTO or ISO members. While it is true that the obligation of nonincumbent transmission developers to expand their transmission facilities, once within an RTO or ISO, may apply to fewer transmission facilities than those of an incumbent with a large footprint, and that some incumbent transmission providers may be subject to different requirements under state and local laws, it does not follow that eliminating federal rights of first refusal amounts to discrimination in favor of nonincumbent transmission developers. Rather, we are merely removing a barrier to participation by all potential transmission providers. With regard to concerns that our reforms will discourage entities from joining or maintaining membership in RTOs and ISOs, we note that a variety of factors must be weighed when evaluating the benefits and burdens of RTO/ISO membership. In addition, we reject Southern Companies' request that we clarify that the reforms related to nonincumbent transmission developers do not apply in non-RTO regions; the reforms apply equally to public utility

transmission providers in all regions. The Commission believes that the modifications and clarifications provided below with regard to the framework under which transmission developers will participate in the transmission planning process will alleviate some of the concerns expressed by commenters.

266. We are not persuaded by commenters who argue that the reliability of the transmission system is a function of the number of public utility transmission providers of that system. In fact, to enhance reliability, among other reasons, public utility transmission providers have historically connected to the transmission systems of others, as well as jointly owned transmission facilities, and have therefore developed experience, protocols, and business models for coordinated operations with multiple transmission providers, operators, and users. Moreover, many of the same commenters that raise reliability concerns also suggest that nonincumbent transmission developers instead pursue the merchant model of development, which similarly increases rather than decreases the number of transmission providers within a region. All providers of bulk-power system transmission facilities, including nonincumbent transmission developers, that successfully develop a transmission project, are required to be registered as functional entities and must comply with all applicable reliability standards.[242] Together with the additional requirements we adopt in section III.B.4 below, the Commission finds these protections sufficient to support our decision here to eliminate the federal rights of first refusal contained in Commission-jurisdictional tariffs and agreements.

267. The Commission recognizes that there may be circumstances when an incumbent transmission provider may be called upon to complete a transmission project that it did not sponsor. For example, a situation may arise where an incumbent transmission provider is called upon to complete a transmission project that another entity has abandoned. There also may be situations in which an incumbent transmission provider has an obligation to build a project that is selected in the regional transmission plan for purposes of cost allocation but has not been sponsored by another transmission developer. We clarify that both of these situations would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA. In addition, the Commission addresses reliability concerns that may arise under those circumstances below.

268. For the foregoing reasons, and in light of the evaluation procedures required in section III.B.3 below, the Commission finds that there is sufficient justification in the record to implement the requirements regarding rights of first refusal contained in Commission-jurisdictional tariffs or agreements. The Commission is not required to identify specific evidence to justify our actions today. Our task in this respect is to show that there is '' 'ground for reasonable expectation that competition may have some beneficial impact.' ''[243] Although the Commission has previously accepted, in some cases, and rejected, in others, a federal right of first refusal, we find more persuasive in light of the comments in this proceeding, the Commission's reasoning in rejecting the federal right of first refusal. In particular, the Commission rejected a right of first refusal based on an expectation that ''[t]he presence of multiple transmission developers would lower costs to customers.''[244] We have carefully considered the record in the proceeding and therefore find further procedures to evaluate the need for the reforms adopted herein to be unnecessary.

269. Finally, we disagree with San Diego Gas & Electric that the elimination of a federal right of first refusal raises concerns under *FPC* v. *Hope Natural Gas Co.* and *Bluefield Water Works* v. *Public Serv. Comm'n.* As San Diego Gas & Electric notes, these cases stand for the principle that utilities are entitled to receive a reasonable return on their investment. They do not, however, speak to the issue of who may make an investment. They thus require only that a utility receive a reasonable rate of return on the investments that it makes, not that the utility receive a preferential right to make those investments.

2. Legal Authority To Remove a Federal Right of First Refusal

a. Commission Proposal

270. In the Proposed Rule, the Commission explained that the existing planning process may not result in a cost-effective solution to regional transmission needs and transmission projects that are in a regional transmission plan therefore may be developed at a higher cost than necessary. The Commission stated that the result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.[245] The Commission also stated that it may be unduly discriminatory or preferential to deny a nonincumbent public utility transmission developer that sponsors a project that is in a regional transmission plan the rights of an incumbent public utility transmission developer that are created by a public utility transmission provider's tariffs or agreements subject to the Commission's jurisdiction. Under these circumstances, the Commission noted that nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. The Commission stated that, if the regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents, it cannot meet the principle of being ''open.''

b. Comments Regarding the Commission's Authority To Implement the Proposal

271. Several commenters argue that the Commission has adequate statutory authority to undertake the reforms in the Proposed Rule.[246] Some of the commenters supporting the Commission's proposal to eliminate federal rights of first refusal from Commission-jurisdictional tariffs and agreements specifically addressed the scope of the Commission's authority under section 206 of the FPA. Primary Power contends that the Commission is authorized under section 206 to remove or limit the right of first refusal, which is a rule, practice, or contract condition subject to its jurisdiction. Primary Power states that, while the proposal to eliminate the right of first refusal represents a change in the Commission's policy of tolerance or occasional acceptance of the right of first refusal, this change in policy is justified as in the public interest. Primary Power

[242] 18 CFR 39.2(a) (2011).

[243] *Wisconsin Gas Company* v. *FERC,* 770 F.2d 1144, 1158 (DC Cir. 1985) (citing *FCC* v. *RCA Communications, Inc.,* 346 U.S. 86, 96 (1953)).

[244] *Cleco Power LLC,* 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings,* 112 FERC ¶ 61,069 (2005); *see also Carolina Power and Light Co.,* 94 FERC ¶ 61,273 at 62,010, *order on reh'g,* 95 FERC ¶ 61,282 at 61,995 (2001) (finding that a federal right of first refusal would unduly limit the planning authority and present the possibility of discrimination by self-interested transmission owners, potentially reduce reliability, and possibly precluding lower cost or superior transmission facilities or upgrades by third parties from being planned and constructed).

[245] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 87–88.

[246] *E.g.,* Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; Multiparty Commenters; and Primary Power.

argues that rights of first refusal are creatures of regulated services that are subject to federally-regulated tariffs and, therefore, proponents of rights of first refusal must find some independent legal basis for the property rights they seek to protect.

272. LS Power argues that the Commission has a duty to stamp out all forms of discrimination in the form of a right of first refusal, whether written in the OATT or other agreement, or simply as part of a long-standing bias arising from a closed planning process. LS Power contends that eliminating rights of first refusal is a critical step toward true competition in the electric industry, and essential to ensuring that new transmission infrastructure is provided to consumers at just and reasonable rates. LS Power notes that the Commission has historically required the elimination of provisions that are anticompetitive on their face.[247] Joined by American Forest & Paper, LS Power further argues that elimination of a federal right of first refusal would not be inconsistent with existing state laws, noting the support for the Commission proposal by a number of state commissions submitting comments.

273. Other commenters contend that the Commission does not have the legal authority to implement the proposed reforms related to rights of first refusal in Commission-jurisdictional tariffs or agreements. Some commenters argue that the FPA does not give the Commission the authority to address discrimination between incumbent and nonincumbent transmission developers, arguing that the FPA's protection against undue discrimination is concerned with the protection of consumer interests and does not extend to nonincumbent transmission developers.[248] Ad Hoc Coalition of Southeastern Utilities states that precedent shows that the rights of competitors are neither protected nor contemplated in FPA section 205(b)'s proscription against undue discrimination.[249] Edison Electric Institute agrees, arguing that an undue discrimination analysis in the context of the right of first refusal provisions and planning processes is unsupportable, explaining that such provisions are not rates, terms, and conditions of a service that a transmission owner provides to its customers. Edison Electric Institute states that the Commission previously has not taken the step of characterizing transmission planning as an obligation or service to non-customers to facilitate their competing efforts to own transmission facilities. Edison Electric Institute further states that the comparability analysis for undue discrimination could not apply because ownership is not a service that a transmission owner provides to itself.

274. Indicated PJM Transmission Owners contend that the undue discrimination concerns underlying Order. No. 888, regarding access to transmission facilities for loads and for competing suppliers of wholesale electricity, are not present here. Indicated PJM Transmission Owners argue the Commission does not and cannot find that relying on incumbent transmission owners to build necessary upgrades to their systems discriminates either in the terms of service available to different classes of transmission customers or in the terms upon which wholesale sellers and buyers gain access to the transmission system.

275. Some commenters analogize to the Commission's jurisdiction under section 205 of the FPA, arguing that there are only two types of undue discrimination actionable under section 205: treating similar customers differently or affording similar treatment to dissimilar customers.[250] Some of these commenters assert that the court in *City of Frankfort* v. *FERC*[251] noted that section 205 provisions focus on the fair treatment of customers. Similarly, Nebraska Public Power District states *Public Service Commission of Indiana*[252] stands for the proposition that the antidiscrimination policy in section 205(b) is violated where one consumer has its rates raised significantly above what other similarly situated consumers are paying.

276. Other commenters also argue that the Commission lacks general jurisdiction over the siting, construction, or ownership of transmission facilities, matters they assert Congress intentionally left to the states, as demonstrated by a comparison between the FPA and the Natural Gas Act.[253] Commenters assert that the proposal to adopt rules governing who can build transmission within an incumbent transmission owner's zone exceeds the authority conferred upon the Commission under the FPA to regulate the terms and conditions of service and, in essence, create a federal franchise for transmission service.[254]

277. Other commenters argue that the Commission is provided only limited backstop siting authority under section 216 of the FPA, a grant of authority that the courts have emphasized is subservient to the primary jurisdiction of the states.[255] Oklahoma Gas & Electric Company argues that, in enacting section 215 of the FPA, Congress expressly declined to grant the Commission the authority to require the construction of facilities or the expansion of the grid. PPL Companies contend that the Commission's jurisdiction under FPA sections 210 and 211 to order existing utilities to enlarge their facilities, if necessary to permit transmission service or interconnection, can be invoked only pursuant to specific procedures and after specific findings are made.

278. Oklahoma Gas & Electric Company asserts that, for the Commission to extend its jurisdiction over actions that indirectly affect activity otherwise governed by the states, the Commission must show that the action in question has a direct and significant effect on jurisdictional rates. Oklahoma Gas & Electric Company argues that the courts are unwilling to allow the Commission to regulate activity if, in so doing, the Commission is directly regulating activity that was specifically reserved for the states.[256]

[247] LS Power (citing *Gulf States Utils. Co.,* 5 FERC ¶ 61,066 (1978)).

[248] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; Nebraska Public Power District; Omaha Public Power District; Xcel; and Indicated PJM Transmission Owners (citing *Grand Council of the Crees* v. *FERC,* 198 F.3d 950, 956 (DC Cir. 2000)).

[249] Ad Hoc Coalition of Southeastern Utilities cites to *Brunswick Corp.* v. *Pueblo Bowl-O-Mat, Inc.,* 429 U.S. 477, 487–89 (1977), *Cargill, Inc.* v. *Montfort of Colorado, Inc.,* 479 U.S. 104, 115–17 (1976), *City of Frankfort* v. *FERC,* 678 F.2d 699, 707 (7th Cir. 1982).

[250] *E.g.,* Nebraska Public Power District; Large Public Power Council; and MISO Transmission Owners. Some of these commenters cite to *Alabama Elec. Coop., Inc.* v. *FERC,* 684 F.2d 20, 27–28 (DC Cir. 1984), *Sacramento Mun. Util. Dist.* v. *FERC,* 474 F.3d 797, 802 (DC Cir. 2007), *City of Vernon* v. *FERC,* 845 F.2d 1042, 1046 (DC Cir. 1988), *Ohio Power Co.* v. *FERC,* 744 F.2d 162, 165 n.3 (DC Cir. 1984), and *"Complex" Consol. Edison Co.* v. *FERC,* 165 F.3d 992, 1012 (DC Cir. 1999).

[251] *City of Frankfort* v. *FERC,* 678 F.2d 699, 704 (7th Cir. 1982).

[252] *Pub. Serv. Comm'n of Indiana, Inc.* v. *FERC,* 575 F.2d 1204, 1213 (7th Cir. 1978).

[253] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Oklahoma Gas and Electric Company; Omaha Public Power District; PPL Companies; Large Public Power Council; Xcel; Indianapolis Power & Light; Edison Electric Institute; Indicated PJM Transmission Owners; and Virginia State Corporation Commission. Indicated PJM Transmission Owners cite to *Altamont Gas Transmission Co.* v. *FERC,* 92 F.3d 1239, 1248 (DC Cir. 1996).

[254] *E.g.,* PPL Companies and PSEG Companies.

[255] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Indicated PJM Transmission Owners; Oklahoma Gas & Electric Company; and PPL Companies. Indicated PJM Transmission Owners cite to *Piedmont Envtl. Council* v. *FERC,* 558 F.3d 304 (4th Cir. 2009).

[256] Oklahoma Gas & Electric Company (citing *Northwest Central Pipeline Corp.* v. *State Corp. Comm'n of Kansas,* 489 U.S. 493 (1989); *Connecticut Dept. of Pub. Util. Control* v. *FERC,* 569

Continued

Oklahoma Gas & Electric Company cites to *National Association of Regulatory Utility Commissioners* v. *FERC,* 475 F.3d 395, 401 (DC Cir. 2004), where the court found that Commission regulations related to generator interconnection procedures bore a close enough relationship to its authority over jurisdictional transmission services that the exercise of jurisdiction over interconnection service was permissible.

279. Commenters opposing the Commission's proposed reforms generally reject the notion that the Commission is acting only to eliminate the federal right of first refusal, stating that the Proposed Rule would go much farther by regulating the protocols for determining the entity responsible to construct an upgrade. Indicated PJM Transmission Owners argue that, to the extent a state-created right is reflected in an RTO or ISO tariff or agreement, it cannot then be converted by the Commission into a federal based right that the Commission can eliminate by its own regulation. Indicated PJM Transmission Owners assert that the fact that the transmission provider may be an RTO or ISO does not expand the Commission's jurisdiction because the transmission owner is still the public utility that makes and supports financial investments. They argue that the Commission cannot use such a voluntary association to require utilities to surrender their statutory rights, in accordance with *Atlantic City Electric Co.* v. *FERC.*[257]

280. Other commenters similarly agree that not every provision of a Commission-jurisdictional rate schedule or tariff governs the terms and conditions of jurisdictional services.[258] For example, PPL Companies argues that there are numerous provisions in agreements required to be filed with the Commission that are not rates or other terms or conditions that affect rates, such as provisions addressing force majeure and indemnification. PPL Companies and others point to provisions in transmission owner agreements or RTO operating agreements that establish governance as an example of terms that are beyond the Commission's jurisdiction.[259] Indicated PJM Transmission Owners argue that, consistent with *CAISO* v. *FERC,* section 206 is not implicated because the building and owning of an upgrade is not a practice or contract that affects a rate, charge, or classification for transmission. Indicated PJM Transmission Owners argue that regulation of the determination of which entity constructs transmission additions and expansions is a regulation of whether the utility can provide a service at all, not the rate for the service. Indicated PJM Transmission Owners explain that *CAISO* v. *FERC* noted that the FPA provides the Commission with limited power regarding corporate governance in section 305, which involves interlocking directorates, and this supports the proposition that section 206 was not intended to reach such matters.[260]

281. Indicated PJM Transmission Owners contend that each of the choices a utility's management makes potentially constitutes a ''practice'' that eventually affects rates insofar as the utility seeks to recover the resulting costs. If the Commission concludes that an investment or other business decision is the product of imprudent management, Indicated PJM Transmission Owners contend that the Commission has authority to consider denying recovery of excessive costs resulting from that decision, not to supplant the public utility's management's decision-making authority.[261] Joined by FirstEnergy Service Company, Indicated PJM Transmission Owners argue that a fundamental premise of the FPA is that a utility has a right to recover prudently incurred costs, and a corollary of this principle is that a utility must have the right to decide whether to make those investments.[262]

282. Indicated PJM Transmission Owners disagree with the Commission's statement that the regional transmission planning processes that do not consider and evaluate of projects proposed by nonincumbent transmission developers cannot meet the principle of being ''open.'' They argue that the Commission cannot, by relying upon nondiscrimination principles, bootstrap authority it does not have for mandating the sponsorship model. Citing *Office of Consumers' Counsel* v. *FERC,*[263] Indicated PJM Transmission Owners argue that the Commission cannot redefine the transmission planning principles adopted in Order No. 890 to encompass matters that were never contemplated when it was issued. Indicated PJM Transmission Owners assert that nothing about the transmission owners' construction rights and obligations prohibits parties from participating in the process or proposing transmission projects. They state that the Commission has offered no rationale for concluding that the requirement of openness must be redefined to include a new sponsorship model.

283. National Grid notes that the rights and obligations of transmission owners in New England to own and construct transmission facilities or upgrades located within or connected to their existing electric systems were extensively litigated in the proceeding where the Commission found that ISO New England satisfied the requirements to be an RTO. National Grid states that in that proceeding, the Commission-approved contractual language in Section 3.09 of ISO New England's Transmission Operating Agreement providing that, absent agreement of ISO New England and the participating transmission owners to an amendment to these provisions, they will be subject to the *Mobile-Sierra* doctrine. Therefore, National Grid argues that the subject provisions cannot be modified by the Commission unless it finds they are contrary to the public interest. It submits that there is no evidence to meet this high standard. National Grid requests that Commission should either clarify that Commission-approved rights to build of transmission owners like those in New England would not be affected by the proposed NOPR requirements, or modify those requirements in the Final Rule to allow transmission owners in New England to continue to meet regional needs under the existing planning process.

c. Commission Determination

284. The Commission determines that it has the authority under section 206 of the FPA to implement the reforms adopted to eliminate provisions in Commission-jurisdictional tariffs and agreements that grant federal rights of first refusal to incumbent transmission

F.3d 477, 484 (DC Cir. 2009); *Mississippi Indus.* v. *FERC,* 808 F.2d 1525, 1542–43 (DC Cir. 1987)).

[257] 295 F.3d 1 (DC Cir. 2002) (*Atlantic City*).

[258] *E.g.,* Oklahoma Gas & Electric; and PPL Companies. In support, Oklahoma Gas & Electric Company cites to *PSI Energy, Inc.,* 55 FERC ¶ 61,254, at 61,811 (1991), *reh'g denied,* 56 FERC ¶ 61,237 (1991).

[259] PPL Companies (citing *CAISO* v. *FERC,* 372 F.3d 395 (DC Cir. 2004)).

[260] In addition, FirstEnergy Service Company states that the court in *CAISO* v. *FERC* explained that a more expansive interpretation of ''practice'' would allow the Commission to regulate a range of subjects that the court considered to be plainly beyond the Commission's authority.

[261] Indicated PJM Transmission Owners (citing *Town of Norwood* v. *FERC,* 80 F.3d 526, 531 (DC Cir. 1996)).

[262] Indicated PJM Transmission Owners (citing *Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n,* 262 U.S. 276, 289 n.1 (1923)). Indicated PJM Transmission Owners also note that Congress did provide similar authority in laws that parallel the FPA, such as section 402 of the Transportation Act of 1920, and sections 5 and 7 of the Natural Gas Act.

[263] *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1148 (DC Cir. 1980).

providers with respect to the construction of transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission's remedial authority under FPA section 206 of the FPA is broad and allows us to act, as we do here, to revise terms in jurisdictional tariffs and agreements that may cause the rates, terms or conditions of transmission service to become unjust and unreasonable or unduly discriminatory or preferential.[264] As explained in the preceding section, granting incumbent transmission providers a federal right of first refusal with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation effectively restricts the universe of transmission developers offering potential solutions for consideration in the regional transmission planning process. This is unjust and unreasonable because it may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, the inclusion of higher-cost solutions in the regional transmission plan. It is squarely within our authority under FPA section 206 to correct this deficiency.

285. A federal right of first refusal is, in the language of section 206(a), a ''rule, regulation, practice, or contract'' affecting the rates for jurisdictional transmission service. Where the Commission finds that such rules, regulations, practices or contracts are ''unjust, unreasonable, unduly discriminatory, or preferential,'' the Commission must 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.'' In light of our finding above that federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings, the Commission is compelled under section 206(a) to take corrective action here. The court in *CAISO* v. *FERC* explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.''[265] The Commission here is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on competition and in turn the rates for jurisdictional transmission services. As explained in greater depth below, these matters fall directly within the ambit of the court's interpretation of a practice affecting rates.

286. In addition, federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. The Commission has long recognized that it has a responsibility to consider anticompetitive practices and to eliminate barriers to competition.[266] Indeed, the Supreme Court has said 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.''[267] In requiring the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements, we are acting in accordance with our duty to maintain competition.

287. Eliminating a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, as some commenters contend, result in the regulation of matters reserved to the states, such as transmission construction, ownership or siting. The reforms are focused solely on public utility transmission provider tariffs and agreements subject to the Commission's jurisdiction. While many commenters indicate that they disagree with these statements, none of them has explained adequately how our actions will override or conflict with state laws or regulations. The Commission acknowledges that there may be restrictions on the construction of transmission facilities by nonincumbent transmission providers under rules or regulations enforced by other jurisdictions. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities. It does not follow that the Commission has no authority to remove such restrictions in the tariffs or agreements subject to its jurisdiction.

288. The Commission disagrees with commenters arguing that the effect of a federal right of first refusal on jurisdictional rates is too tenuous to support action. These commenters argue that the holding of *CAISO* v. *FERC*,[268] prevents us from treating a federal right of first refusal as a practice that affects transmission rates. In that case, the court held that the Commission has no authority to replace the selection method or membership of the governing board of the California ISO, which had been established under state law.[269] The court found that such internal governance practices were too remote from the California ISO's rate structure to be considered practices that affect rates for purposes of section 206 and, as a result, rejected the Commission's attempt to impose governance requirements that conflicted with state law.[270]

289. Here, however, the Commission is focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on the rates for jurisdictional transmission services and on undue discrimination. This extends well beyond the internal corporate governance matters at issue in *CAISO* v. *FERC*. The federal rights of first refusal at issue in this proceeding can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs and, as a result, increasing the cost of transmission development that is recovered from jurisdictional customers through rates. The selection of transmission facilities in a regional transmission plan for purposes of cost allocation is therefore, unlike corporate governance matters, directly related to costs that will be allocated to jurisdictional ratepayers.

290. Other commenters rely on *Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n* for the proposition that, because a utility has a right to recover prudently incurred costs, it has a corollary right to decide whether to incur those costs, which the Commission cannot violate by eliminating a federal right of first refusal. In that case, the court explained that a utility's right to make investment decisions is grounded in the business judgment rule, which prevents courts from substituting their judgment on the prudence of investment decisions for that of corporate directors and officers.[271] Nothing in that case, however, supports a claim to an exclusive right to make investments under a federal right of first refusal, only the need to defer to business judgment when investment decisions are in fact

[264] *Associated Gas Distributors*, 824 F.2d 981, 1008 (DC Cir. 1985).

[265] *CAISO* v. *FERC*, 372 F.3d 395 at 403.

[266] *Gulf States Utils. Co.*, 5 FERC ¶ 61,066 at 61,098.

[267] *Otter Tail Power Co.* v. *United States*, 410 U.S. 366 at 374 (1973).

[268] 372 F.3d 395 at 399.

[269] *CAISO* v. *FERC*, 372 F.3d 395 at 398.

[270] *Id.* at 403.

[271] *See Mo. ex. rel. Southwestern Bell Tel. Co.* v. *Pub. Serv. Comm'n*, 262 U.S. 276, 289 (1923).

made. In removing a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is drawing no conclusion regarding the prudence of any investment decision, nor is the Commission seeking to determine which particular entity should construct any particular transmission facility. The effect of these reforms is to allow more types of entities to be considered for potential construction responsibility, not to make choices among those transmission developers or their proposed transmission facilities.

291. The Commission therefore determines that these reforms regarding elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements are not prevented by state law or otherwise limited by the FPA. In directing the removal of a federal right of first refusal from Commission-jurisdictional tariffs and agreements, the Commission is not ordering public utility transmission providers to enlarge their transmission facilities under sections 210 or 211 of the FPA, nor making findings related to our authorities under section 215 or 216. Similarly, nothing in our actions today is inconsistent with our obligations under section 217. Indeed, section 217(b)(4) directs the Commission to exercise its authority ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load serving entities to satisfy [their] load serving obligations.'' Greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load serving entities and increased access to resources.

292. We decline to address at this time the merits of National Grid's arguments that section 3.09 of the ISO New England Transmission Operating Agreement establishes a federal right of first refusal that can be modified only if the Commission makes the findings that National Grid contends are required by application of the *Mobile-Sierra* doctrine.[272] We find that the record is not sufficient to address the specific issues raised by National Grid in this generic proceeding. Moreover, we generally do not interpret an individual contract in a generic rulemaking, and we are not persuaded to do so here given the limited record developed so far on section 3.09. Thus, we conclude that these arguments, including National Grid's argument as to the applicable standard of review, are better addressed as part of the proceeding on ISO New England's compliance filing pursuant to this Final Rule, where interested parties may provide additional information.

3. Removal of a Federal Right of First Refusal From Commission-Jurisdictional Tariffs and Agreements

a. Commission Proposal

293. In the Proposed Rule, the Commission sought comment on a framework to eliminate from a transmission provider's OATT or agreements subject to the Commission's jurisdiction provisions that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities that are included in a regional transmission plan. The Commission proposed to require each public utility transmission provider to revise its OATT to: (1) Establish appropriate qualification criteria for determining an entity's eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer; (2) include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process, and provide a single, specified date by which proposals must be submitted; (3) describe a transparent and not unduly discriminatory or preferential process used by the region for evaluating whether to include a proposed transmission facility in a regional transmission plan; (4) remove, along with corresponding changes in any other Commission-jurisdictional agreement, provisions that establish a federal right of first refusal for an incumbent transmission provider and include a description of how the regional transmission planning process provides a right to construct a selected project to the project sponsor, including potential modifications to proposed projects; (5) provide the right to develop a project for a defined period of time if not initially included in a regional transmission plan; and, (6) provide a comparable opportunity for incumbent and nonincumbent transmission project developers to recover the cost of a transmission facility through a regional cost allocation method.[273]

294. Under this framework, the Commission proposed that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. The Commission stated that both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan. The Commission proposed that the tariff changes to implement these proposed reforms would be developed through an open and transparent process involving the public utility transmission provider, its customers, and other stakeholders.

295. Given the interrelated nature of comments regarding the first two and the remaining four elements of the Commission's proposed framework, the Commission groups comments accordingly and then turns to addressing the comments collectively.

b. Comments Regarding Developer Qualification and Project Identification

296. A number of commenters address issues related to the first two aspects of the Commission's proposed framework, governing mechanisms by which entities could propose a project in the regional transmission planning process.[274] San Diego Gas & Electric contends that any qualification criteria for potential transmission developers should address all of the technical and financial capabilities necessary for the entity to support the transmission project, if approved, for its expected lifetime, including provisions of security and insurance, as well as other requirements, such as those relating to the proponent's capital structure. Wind Coalition agrees that transmission project developers should be required to satisfy certain financial standards to ensure that they can properly construct and maintain their proposed projects. According to Wind Coalition, the experience of the Competitive

[272] In support of its argument, National Grid cites *ISO New England, Inc.,* 109 FERC ¶ 61,147, at P 78 (2004). In that order, the Commission stated, ''We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides direction to the Transmission Owners and the ISO–NE RTO to follow planning procedures contained in the ISO–NE RTO OATT. As such, this provision will have no adverse impact on third parties or the New England market.''

[273] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 90–96.

[274] *E.g.,* American Transmission; Connecticut & Rhode Island Commissions; Federal Trade Commission; Integrys; ISO–NE; Large Public Power Council; MidAmerican; Massachusetts Departments; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; New Jersey Board; NextEra; Northeast Utilities; and Western Independent Transmission Group.

Renewable Energy Zones in ERCOT has demonstrated the need for a selection procedure that provides for: Clearly defined standards for selection; selection within a reasonable time period; and a definite beginning and ending date to avoid unnecessary delay in selection and construction and to prevent a strategy of delay or gamesmanship.

297. Most commenters that weighed in on this issue urge the Commission not to adopt a one-size-fits-all set of requirements and, instead, allow each region to develop criteria appropriate for the region.[275] A number of commenters, however, encourage the Commission to identify the types of criteria that must be addressed to codify expectations and ensure that all entities are operating under the same requirements.[276] Old Dominion recommends that the following criteria be used to evaluate proposers of projects: Financial viability; technical expertise; authority or ability to obtain and meet all necessary regulatory requirements, including condemnation where necessary; and an exit strategy to address how the facilities can or will be transferred if an entity is no longer able to meet financial or other obligations associated with the project. PJM supports a requirement that each project developer demonstrate that it has received up-front authority to site its project from the relevant states because, without such authority, it would be fruitless to designate a project to the prospective project developer. In reply, however, Atlantic Wind Connection disagrees with PJM, instead suggesting that developers receive state siting approval within a reasonable time after selection of the project in a regional transmission plan.

298. While many commenters endorse requiring project developers to meet qualification criteria showing their financing and technical capabilities, some argue that the rules cannot be one-sided against nonincumbents so as to amount to a backdoor right of first refusal.[277] LS Power states, for example, that an entity that is financially qualified but is deemed to not be technically qualified should be permitted to partner with a technically qualified entity. Pattern Transmission states that, if a transmission provider determines that a project developer does not meet the qualification criteria, it should be required to provide the rationale for that determination to the applicant in writing so that any future attempt to meet the qualification criteria will be better informed. Other commenters express concern that the qualification criteria not be so onerous that they cannot be readily satisfied by existing transmission owners.[278] APPA and Transmission Access Policy Group suggest that qualification criteria be crafted in a way that supports a variety of ownership arrangements, including joint ownership by public power systems.

299. Some commenters oppose or otherwise raise concerns regarding the use of qualification criteria to determine eligibility to propose projects in the regional transmission planning process.[279] PPL Companies state that RTOs do not have experience in evaluating the capabilities of nonincumbent transmission developers and that both the establishment and application of the criteria are likely to result in disputes and litigation. Indianapolis Power & Light states that, because incumbents have existing state obligations to serve, incumbent transmission owners should be deemed to meet any qualification criteria without any additional showing. Pacific Gas & Electric similarly argues that qualification criteria should take into consideration the ability of incumbent transmission owners to provide cost and efficiency benefits that may not be available from a single-project transmission owner, such as in obtaining siting and permitting approvals.

300. Several commenters address the use of a form to obtain information from prospective transmission developers as to projects submitted for evaluation in the regional transmission planning process.[280] LS Power asks the Commission to set forth the requisite project information required in such a form, subject to any region or transmission provider obtaining Commission approval to modify such requirements. California ISO suggests that, notwithstanding its general opposition to the elimination of federal rights of first refusal, any requirements imposed on project developers to submit information in support of a proposal should include the submission of sufficient study results evidencing a *prima facie* case that the project is needed. Exelon contends that project proposals should be required to include technical analyses demonstrating that they meet the region's requirements and that a developer should not be provided with any priority rights without such supporting documentation. Transmission Agency of Northern California asks the Commission to clarify that the evaluation form should be developed in the regional transmission planning process and that a project developer would not be required to submit separate and distinct forms to each public utility transmission provider that participates in a given regional transmission planning process.

301. LS Power supports the proposal for public utility transmission providers to identify a specified date by which to submit proposed transmission projects, generally arguing that a submission deadline would promote orderly and fair consideration of projects.[281] Others oppose the proposal, generally arguing that existing transmission planning processes are iterative in nature.[282] For example, New England States Committee on Electricity states that establishing such a deadline could have the unintended consequence of discouraging discussion of emerging needs and alternative ways to meet them. It suggests that the Commission leave such procedural matters to the regions for consideration. Some commenters express concern that the Commission's proposal invites gaming, creating an incentive to propose a host of projects so that individual entities may obtain their own time-based rights of first refusal to develop proposals.[283] LS Power disagrees in reply, arguing that such concerns could be addressed by requiring transmission developers to post a reasonable deposit, which could be based in part on the total estimated cost to develop the annual plan and the number of transmission projects evaluated in the plan, to avoid new projects being filed in an effort to prevent others from developing them.

[275] *E.g.,* New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[276] *E.g.,* Edison Electric Institute; California ISO; Pacific Gas & Electric; Exelon; Southern California Edison; Southern Companies; PJM; and National Grid.

[277] *E.g.,* Anbaric and PowerBridge; LS Power; and Pattern Transmission; and Primary Power. Anbaric and PowerBridge cite to *New England Indep. Transmission Co., L.L.C.,* 118 FERC ¶ 61,127 (2007).

[278] *E.g.,* New York ISO; Transmission Agency of Northern California; California Commissions; Arizona Public Service Company; Northeast Utilities; and SPP.

[279] *E.g.,* PPL Companies; Indianapolis Power & Light; and Pacific Gas & Electric.

[280] *E.g.,* California ISO; Edison Electric Institute; LS Power; and Transmission Agency of Northern California.

[281] *E.g.,* LS Power.

[282] *E.g.,* Edison Electric Institute; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

[283] *E.g.,* Edison Electric Institute; Exelon; MISO Transmission Owners; California ISO; ISO New England; NEPOOL; Northeast Utilities; New England States Committee on Electricity; and National Rural Electric Coops.

c. Comments Regarding Project Evaluation and Selection

302. Commenters also address the remaining four aspects of the Commission's proposed framework for eliminating federal rights of first refusal, relating to mechanisms to evaluate, select and recover the costs of projects proposed in the regional transmission planning process. Most commenters support the proposal that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted through a transparent and not unduly discriminatory or preferential process.[284] For example, Duke and National Grid state that existing regional transmission planning processes already evaluate proposed projects through an open process described in the relevant public utility transmission providers' OATTs.

303. Several commenters suggest that regional flexibility is needed when determining the procedures by which transmission projects are evaluated and selected.[285] For example, Connecticut & Rhode Island Commissions and Massachusetts Departments state that ensuring equal rights and obligations of incumbent and nonincumbent transmission developers would raise a number of questions that will need to be addressed through the stakeholder process, including how projects and developers are selected, how non-transmission alternatives will be evaluated, how rights of way are negotiated, and how to address cost overruns. They state that the Final Rule should recognize the many issues that would arise following the proposed change and allow the stakeholder process flexibility to identify and develop solutions to these challenges. Western Independent Transmission Group suggests the use of an independent third-party observer may be necessary to oversee the evaluation and selection of competing transmission projects to give market participants and the Commission assurance that the process is fairly and efficiently managed.

304. A number of commenters characterize the Commission's proposal as implementing a sponsorship model that conflicts with the collaborative nature of current transmission planning processes.[286] North Dakota & South Dakota Commissions state that the sponsorship paradigm will turn current transmission planning processes into an unmanageable free for all, undermining the effective evaluation of potential transmission solutions. Integrys and Southern Companies contends that sponsorship rights may do more harm than good and will defeat the objective of an orderly and systematic planning and construction process, increasing disputes, creating queuing problems, disrupting existing OATT processes, harming reliability, and resulting in a loss of flexibility. Baltimore Gas & Electric argues that those that want to claim sponsorship rights also do not want to provide the RTO with discretion to deny their claim and that such entities could tie up transmission construction as long as they want until they ensure they are the builders. National Rural Electric Coops suggest that the Commission convene a technical conference to address complex implementation issues.

305. Southern Companies also question how transmission proposals submitted by nonincumbent transmission providers should be evaluated in the regional transmission planning process. Southern Companies state that the Proposed Rule could be viewed as permitting any qualified entity to sponsor projects at the regional level, where a ''black box'' evaluation process would be applied to determine the ''winners.'' Southern Companies suggest that nonincumbent transmission developers be treated similarly to the integration of merchant generation so that state law would not be undermined. That is, Southern Companies recommend that, if a nonincumbent transmission developer has a proposal that the incumbent utility believes to be cost-effective and reliable, that developer would have to join with Southern Companies to petition the relevant state regulatory authorities for approval for construction and rate recovery.

306. Some commenters argue that the Commission should not require development of mechanisms that provide construction rights to nonincumbent transmission developers seeking to develop projects solely within an existing transmission owner's footprint or that use rights-of-way held by existing transmission owners.[287] For example, Edison Electric Institute asks the Commission to clarify that only an incumbent transmission owner should be allowed to propose local, single system facilities that are simply rolled up into a regional plan, as well as upgrades or modifications to facilities owned by an incumbent transmission provider, including reconductoring, tower change outs, additional facilities in existing substations, facilities in a right of way owned by the incumbent, and new substations cut into existing lines. It argues that allowing nonincumbent transmission developers to perform upgrades to an incumbent transmission owner's transmission facilities could delay upgrades necessary to maintain system reliability and increase the costs of constructing and maintaining such transmission facilities. PJM agrees, arguing that existing transmission owners are in the best position to use their own resources. Imperial Irrigation District expresses concern regarding the potential impact of the Proposed Rule on contractual rights in existing joint ownership and operation agreements governing existing facilities. LS Power cautions that, to the extent the Commission provides for the retention of federal rights of first refusal for existing facilities, the limitations of such an exclusion must be clearly described in the OATT.

307. A number of commenters suggest that the Commission modify the proposal for sponsors of proposed transmission projects to retain the right to build projects of a similar scope for a defined period of time.[288] Bonneville Power states that this proposed reform creates the potential for increased litigation to determine whether an incumbent transmission owner's project is substantially similar to a previously proposed non-incumbent transmission developer's project. Xcel and others [289] contend that selection among similar projects for inclusion in the regional transmission plan is inherently subjective and, therefore, determining whether a project is a modification of a previously proposed project or sufficiently different to be considered a

[284] *E.g.,* Federal Trade Commission; PUC of Nevada; Massachusetts Departments; New England States Committee on Electricity; California Commissions; Connecticut & Rhode Island Commissions; LS Power; FirstWind; National Grid; Western Independent Transmission Group; Transmission Agency of Northern California; Northern California Power Agency; Pattern Transmission; American Transmission; California State Water Project; Anbaric and PowerBridge; PPL Companies; Green Energy and 21st Century; Duke; and Old Dominion.

[285] *E.g.,* Connecticut & Rhode Island Commissions; National Grid; New England States Committee on Electricity; KCP&L; Edison Electric Institute; and WIRES.

[286] *E.g.,* Baltimore Gas & Electric; Edison Electric Institute; Integrys; MISO Transmission Owners; North Dakota & South Dakota Commissions; PSEG Companies; PPL Companies; and Southern Companies.

[287] *E.g.,* Anbaric and PowerBridge; California Municipal Utilities; Edison Electric Institute; Exelon; Imperial Irrigation District; LS Power; PJM; and Southern California Edison.

[288] *E.g.,* California Municipal Utilities; Exelon; LS Power; Northern Tier Transmission Group; and Transmission Agency of Northern California.

[289] *E.g.,* Duke; PPL Companies; MidAmerican; and North Dakota and South Dakota Commissions.

new project would be difficult. National Rural Electric Coops ask the Commission to clarify that the proposal does not prevent an incumbent transmission provider from making minor modifications to a competing transmission project to better meet the needs of the participants in the process.

308. Some commenters argue that the Commission should implement competitive bidding processes for selecting project developers instead of relying on a sponsor-based mechanism for determining construction rights.[290] For example, Transmission Access Policy Study Group contends that competitive bidding yields lower costs to consumers, includes mechanisms to limit cost overruns, and restricts the ability of winning bidders to transfer construction rights. It suggests that any competitive bidding process employed by the Commission favor projects that are jointly owned. California ISO states that its competitive solicitation framework for economic and public policy transmission projects meets the Commission's goals of ensuring development of cost-effective transmission facilities, providing ratepayer benefits, optimizing participation in the transmission planning process, and providing opportunities for nonincumbent transmission developers, although California ISO opposes the use of competitive solicitations for reliability projects. Edison Electric Institute and Ad Hoc Coalition of Southeastern Utilities contend that mandating competitive bidding would undermine existing transmission planning processes and allow nonincumbent developers to bid selectively only for advantageous projects. Pattern Transmission responds that such ''cherry picking'' concerns can be addressed through properly structured competitive bidding processes.

309. With regard to the period for which development rights could be retained, LS Power recommends that a transmission developer that sponsors a transmission project be permitted to retain the right to build or build and own the transmission project for a minimum of five years, while California Municipal Utilities suggest a period of two years. Others express concern with the impact of the Commission's proposal, generally arguing such a policy would encourage entities to submit multiple proposals to maximize potential development opportunities.[291] For example, National Rural Electric Coops suggest this would create an approach to transmission planning in which immutable transmission proposals compete against each other in a form of baseball arbitration (in which the arbitrator must pick one side's offer without modification), even if minor changes to one or more of the proposals would allow them to better meet the needs of consumers in the region. LS Power and Transmission Agency of Northern California disagree, arguing that objective rules can be established to identify when a modified project is the functional equivalent of a sponsored project.

310. Arizona Corporation Commission stresses that, in all cases, proposed transmission projects resubmitted for consideration must be freshly evaluated in each transmission planning cycle so that projects address current needs and requirements. Northern Tier Transmission Group recommends that a project that is not selected in the regional transmission plan must have similar performance characteristics and costs when resubmitted for consideration. California Municipal Utilities argue that a project sponsor should not receive a priority right during resubmission if the transmission project sponsor is only interested in selling that right.

311. Some commenters seek clarification of the obligations that would be imposed on nonincumbent transmission developers as a result of selection of its project for construction.[292] MISO Transmission Owners and New York Transmission Owners contend that, if the proposed reforms are implemented, the Commission should make clear that a nonincumbent transmission developer's right to participate in the transmission planning process must be accompanied by an obligation that it satisfy all the requirements expected of transmission developers in the regional transmission planning process. MISO Transmission Owners state that this clarification is particularly important because institutional investors may seek to invest in transmission facilities to earn the stable return on their investment that a rate-regulated business would provide but have no intention to become public utilities once the facility is placed into service and put under the functional control of an RTO. Minnesota PUC and Minnesota Office of Energy Security suggest that winning transmission projects, regardless of ownership type, should be subject to regulatory scrutiny to make sure that when completed the transmission project fulfills the needs initially ascribed to it and that the transmission project costs are consistent with the cost levels initially proposed.

312. Finally, commenters also address whether the selection of a transmission facility proposed by a nonincumbent transmission developer for inclusion in the regional transmission plan should be eligible for regional cost allocation.[293] Massachusetts Departments and Connecticut & Rhode Island Commissions agree with the basic principle, but argue that recovery should be determined by project criteria and not on the basis of the type of developer proposing the project. SPP and Old Dominion support the proposal, provided that the nonincumbent transmission developer is subject to the same responsibilities as incumbent transmission owners pursuant to the transmission planning requirements. MISO Transmission Owners raise the possibility that a nonincumbent project selected in the regional transmission planning process may be rejected by a state agency in favor of an incumbent transmission owner and question whether under this scenario an incumbent transmission owner would be required to build the project but would not be eligible for regional cost recovery. Ad Hoc Coalition of Southeastern Utilities assert that the proposal may conflict with state-based mandates, explaining that the majority of transmission costs in the Southeast are incurred to serve native load, and are included in rates established pursuant to state or local regulation.

d. Commission Determination

313. The Commission directs public utility transmission providers, subject to the modifications to the Proposed Rule discussed below and subject to the framework discussed and adopted below, to eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a

[290] *E.g.,* Transmission Access Policy Study Group; Pattern Transmission; and Indianapolis Power & Light.

[291] *E.g.,* Connecticut & Rhode Island Commissions; Indianapolis Power & Light; Indicated PJM Transmission Owners; Massachusetts Departments; National Rural Electric Coops; and Oklahoma Gas & Electric.

[292] *E.g.,* New York Transmission Owners; Edison Electric Institute; MISO Transmission Owners; Southern Companies; and Transmission Agency of Northern California.

[293] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; FirstEnergy Service Company; MISO Transmission Owners; New York ISO; Old Dominion; and SPP.

regional transmission plan for purposes of cost allocation.

314. As explained in the preceding sections, the elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements is necessary and appropriate to ensure that rates for jurisdictional services are just and reasonable. However, based on the comments received in response to the Proposed Rule, the Commission modifies the specific requirements placed on public utility transmission providers to implement the proposal and provides clarification regarding those requirements to facilitate compliance.[294]

315. To place our actions in context, the Commission reiterates the existing requirements of Order No. 890 as implemented by public utility transmission providers. As noted by commenters, Order No. 890 already requires public utility transmission providers to have in place processes for evaluating the merits of proposed transmission solutions offered by potential developers.[295] To ensure comparable treatment of all resources, the Commission has required public utility transmission providers to include in their OATTs language that identifies how they will evaluate and select among competing solutions and resources.[296] This includes the identification of the criteria by which the public utility transmission provider will evaluate the relative economics and effectiveness of performance for each alternative offered for consideration.[297] Given that the regions already have processes in place to evaluate competing transmission projects in their transmission planning process, the fundamental question raised in the Proposed Rule is whether additional requirements are needed to ensure that these processes are not adversely affected by federal rights of first refusal. The Commission concludes that such requirements are necessary and, accordingly, adopts the framework set forth in the Proposed Rule with modification.

316. Opponents of the Commission's proposed elimination of federal rights of first refusal argue that this framework represents a fundamental shift in the way that transmission is planned in existing regional processes. These commenters contend that characterizing existing transmission owners as developers of sponsored transmission facilities that are to be evaluated on a comparable basis to proposals submitted by nonincumbent transmission developers transforms, in their view, the collaborative and iterative transmission planning process into a sponsorship-driven competition for new investment opportunities. As we explain elsewhere, the reforms adopted in this Final Rule build upon the requirements of Order No. 890 with respect to transmission planning. Public utility transmission providers already have put in place mechanisms to provide for comparative evaluation of competing solutions. We recognize that the mechanisms for evaluating proposals under this Final Rule will have greater implications because we are also requiring a just and reasonable and not unduly discriminatory process to grant to a transmission developer the ability to use the regional cost allocation method associated with each transmission facility selected in the regional transmission plan for purposes of cost allocation. However, we disagree that the reforms in the Proposed Rule, as modified herein, will make the planning process unmanageable, as suggested by some commenters.

317. Some of the concerns expressed by commenters appear to be driven by the phrasing used in the Proposed Rule to present the framework for removing federal rights of first refusal. There, the Commission stated that both incumbent and nonincumbent transmission developers should share similar benefits and obligations, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan.[298] The Commission's focus in the Proposed Rule on sponsorship of proposed transmission facilities, whether by incumbent transmission providers or nonincumbent transmission developers, appears to have led many commenters to conclude that every transmission facility being planned by an incumbent transmission provider is, in effect, sponsored by that entity and, therefore, could no longer be subject to a federal right of first refusal. The Commission clarifies that this was not the intent of the Proposed Rule, nor is it the intent of the requirements adopted in this Final Rule.

318. The Commission's focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation.[299] As Edison Electric Institute notes, in those regions relying on ''bottom up'' local transmission planning, a transmission facility that is in a public utility transmission provider's local transmission plan might be ''rolled-up'' and listed in a regional transmission plan to facilitate analysis at the regional level. However, the transmission facility from the local transmission plan might not have been proposed in the regional transmission planning process and might not have been selected in the regional transmission plan for purposes of cost allocation by going through an analysis in the regional transmission planning process. The Commission does not, in this Final Rule, require removal from Commission-jurisdictional tariffs and agreements of a federal right of first refusal as applicable to a local transmission facility, as that term is defined herein.[300]

319. In addition, the Proposed Rule emphasized that our reforms do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation.[301] In other words, an incumbent transmission provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities. In addition, the Commission affirms that proposal here, and in response to commenters adds that our reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way. That is, this Final Rule does not remove or limit any right an incumbent may have to build, own and

[294] The requirements adopted here apply only to public utility transmission providers that have provisions in their tariffs or other Commission-jurisdictional agreements granting a federal right of first refusal that is inconsistent with the requirements of this Final Rule. If no such provisions are contained in a public utility transmission provider's tariff or other Commission-jurisdictional agreement, it should state so in its compliance filing.

[295] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494; Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 215–16.

[296] *See, e.g., New York Independent System Operator, Inc.,* 129 FERC ¶ 61,044 at P 35.

[297] *Id.*

[298] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 93.

[299] In order for a transmission facility to be eligible for the regional cost allocation methods, the region must select the transmission facility in the regional transmission plan for purposes of cost allocation. For those facilities not seeking cost allocation, the region may nonetheless have those transmission facilities in its regional transmission plan for information or other purposes, and then having such a facility in the plan would not trigger regional cost allocation.

[300] *See* definition *supra* section II.D of this Final Rule.

[301] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 97.

recover costs for upgrades to the facilities owned by an incumbent, nor does this Final Rule grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation. The retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way.

320. Through the reforms to regional planning required in this Final Rule, the Commission is seeking to ensure that a robust process is in place to identify and consider regional solutions to regional needs, whether initially identified through ''top down'' or ''bottom up'' transmission planning processes. Combined with the cost allocation and other reforms adopted in this Final Rule, implementation of this framework to remove federal rights of first refusal will address disincentives that may be impeding participation by nonincumbent transmission developers in the regional transmission planning process. The extent to which any existing regional transmission planning process must be changed to implement the framework set forth below will depend on the mechanisms used by the region to evaluate competing transmission projects and developers.

321. For example, this Final Rule permits a region to use or retain an existing mechanism that relies on a competitive solicitation to identify preferred solutions to regional transmission needs, and such an existing process may require little or no modification to comply with the framework adopted in this Final Rule.[302] In regions relying primarily on ''top down'' mechanisms pursuant to which regional planners independently identify regional needs and more efficient and cost-effective solutions, existing procedures that allow for stakeholders to offer potential solutions for consideration could provide a foundation for implementing the framework below. In other regions emphasizing the development of local transmission plans prior to analysis at the regional level of alternative solutions, additional procedures may be required to distinguish between those transmission facilities that are proposed to be selected in the regional transmission plan for purposes of cost allocation and those that are merely ''rolled up'' for other purposes.

322. The Commission concludes that the framework adopted below provides sufficient flexibility for public utility transmission providers in each region to determine, in the first instance, how best to address the removal of federal rights of first refusal from Commission-jurisdictional tariffs and agreements. Because we are allowing for regional flexibility and encouraging stakeholders to participate fully in the implementation of this framework by public utility transmission providers, we decline to decide in this Final Rule to convene a technical conference to further explore issues related to federal rights of first refusal, as suggested by some commenters. With the foregoing background in mind, the Commission turns to the specific requirements of this framework below.

i. Qualification Criteria To Submit a Transmission Project for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

323. First, the Commission requires each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer. These criteria must not be unduly discriminatory or preferential. The qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate and maintain transmission facilities.

324. The Commission agrees with commenters that qualification criteria are necessary, and that adoption of one-size-fits-all requirements would not be appropriate. It is important that each transmission planning region have the flexibility to formulate qualification criteria that best fit its transmission planning processes and addresses the particular needs of the region. Such criteria could address a range of issues raised by commenters, such as commitments to be responsible for operation and maintenance of a transmission facility.[303] The Commission stresses, however, that appropriate qualification criteria should be fair and not unreasonably stringent when applied to either the incumbent transmission provider or nonincumbent transmission developers. The qualification criteria should allow for the possibility that an existing public utility transmission provider already satisfies the criteria and should allow any transmission developer the opportunity to remedy any deficiency. Within these general parameters, we leave it to each region to develop qualification criteria that are workable for the region, including procedures for timely notifying transmission developers of whether they satisfy the region's qualification criteria and opportunities to mitigate any deficiencies.[304]

ii. Submission of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

325. Second, the Commission requires that each public utility transmission provider revise its OATT to identify: (a) The information that must be submitted by a prospective transmission developer in support of a transmission project it proposes in the regional transmission planning process; and (b) the date by which such information must be submitted to be considered in a given transmission planning cycle. The Commission declines to adopt the proposal to require a specific form to be developed for the purpose of submitting this information, given that the data to be submitted may not be easily reduced

[302] For example, the Commission has found that competitive solicitation processes can provide greater potential opportunities for independent transmission developers to build new transmission facilities. *See, e.g., California Indep. Sys. Operator,* 133 FERC ¶ 61,224 (2010). However, the Commission declines to adopt commenter suggestions to mandate a competitive bidding process for selecting project developers. While the Commission agrees that a competitive process can provide benefits to consumers, we continue to allow public utility transmission providers within each region to determine for themselves, in consultations with stakeholders, what mechanisms are most appropriate to evaluate and select potential transmission solutions to regional needs.

[303] The Commission notes, however, that nothing in the qualification requirement of this Final Rule precludes a transmission developer from entering into voluntary arrangements with third parties, including any interested incumbent transmission provider, to operate and maintain a transmission facility. Similarly, nothing this Final Rule creates an obligation for an incumbent transmission provider to operate and maintain a transmission facility developed by another transmission developer. Additionally, nothing in the qualifications requirement of this Final Rule is intended to change any existing RTO or ISO procedure or practice regarding the operation of one or more existing transmission facilities.

[304] To be clear, the qualification criteria required herein should not be applied to an entity proposing a transmission project for consideration in the regional transmission planning process if that entity does not intend to develop the proposed transmission project. The Order No. 890 transmission planning requirements allow any stakeholder to request that the transmission provider perform an economic planning study or otherwise suggest consideration of a particular transmission solution in the regional transmission planning process.

to entries on a form. To ensure consistency in the region, however, the Commission requires each public utility transmission provider that has its own OATT to have in that OATT the same information requirements as other public utility transmission providers in the same transmission planning region, as requested by Transmission Agency of Northern California.

326. These information requirements must identify in sufficient detail the information necessary to allow a proposed transmission project to be evaluated in the regional transmission planning process on a basis comparable to other transmission projects that are proposed in the regional transmission planning process. They may require, for example, relevant engineering studies and cost analyses and may request other reports or information from the transmission developer that are needed to facilitate evaluation of the transmission project in the regional transmission planning process. Beyond these minimum requirements, the Commission provides each region with discretion to identify the information to be required, so long as such requirements are fair and not so cumbersome as to effectively prohibit transmission developers from proposing transmission projects, yet not so relaxed that they allow for relatively unsupported proposals. Whether the region wishes to require *prima facie* showings of need for a project, as suggested by the California ISO, should be addressed in the first instance by public utility transmission providers in consultation with stakeholders within the region. The Commission will review the resulting information requirements on compliance and provide further guidance at that time, if necessary.

327. The Commission disagrees that requiring the identification of a date by which information must be submitted for consideration in a given transmission planning cycle undermines the iterative nature of transmission planning or amounts to creation of a time-based federal right of first refusal. Without some reasonable limitation on the submission of new information, public utility transmission providers would never be able to complete the analysis needed to complete their region's transmission plan. However, each region may determine for itself what deadline is appropriate, including potentially the use of rolling or flexible dates to reflect the iterative nature of their transmission planning processes. Given our decision to eliminate the proposed ongoing right to develop previously-sponsored transmission projects, the Commission believes it is not necessary to require here additional procedural protections such as the posting of deposits, as suggested by LS Power. To the extent stakeholders in a particular region believe such procedures have merit, they may consider them during the development of OATT proposals that comply with the requirement of this Final Rule.

iii. Evaluation of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

328. Third, the Commission requires each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation. This process must comply with the Order No. 890 transmission planning principles, ensuring transparency, and the opportunity for stakeholder coordination. The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation. In complying with this requirement, the Commission encourages public utility transmission providers to build on existing regional transmission planning processes that, consistent with Order Nos. 890 and 890–A, already set forth the criteria by which the public utility transmission provider evaluates the relative economics and effectiveness of performance for alternative solutions offered during the transmission planning process.

329. In light of comments received in response to the Proposed Rule, we also require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations. We appreciate that there are many sources of delay that could affect the timing of transmission development, and do not intend to require constant reevaluation of delays that do not materially affect the ability of an incumbent transmission provider to meet its reliability needs or service obligations. Our focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. Under such circumstances, an incumbent transmission provider must have the ability to propose solutions that it would implement within its retail distribution service territory or footprint that will enable it to meet its reliability needs or service obligations. If such other solution is a transmission facility, public utility transmission providers in the regional transmission planning process should evaluate the proposed solution for possible selection in the regional transmission planning process for purposes of cost allocation. As we have explained elsewhere in this Final Rule,[305] nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.

330. The Commission appreciates that the selection of any transmission facility in the regional transmission plan for purposes of cost allocation requires the careful weighing of data and analysis specific to each transmission facility and, in some instances, may be difficult or contentious. While the Commission appreciates the challenges presented by such an evaluation, the requirement to engage in a comparative analysis of proposed solutions to regional needs has been in place since Order No. 890. The Commission encourages public utility transmission providers to consider ways to minimize disputes, such as through additional transparency mechanisms, as they identify enhancements to regional transmission planning processes necessary to comply with this Final Rule.[306] The Commission declines, however, to mandate the use of independent third-party observers, as suggested by Western Independent Transmission Group. To the extent public utility transmission

[305] *See supra* P 256.

[306] Additionally, as described in section III.A, the requirements of the dispute resolution principle order of Order No. 890 apply to the regional transmission planning process as reformed by this Final Rule.

providers in consultation with other stakeholders in a region wish, they may propose to use an independent third-party observer and we will review any such proposal on compliance.

331. By requiring the evaluation of proposed transmission solutions in the regional transmission planning process, the Commission is not dictating that any particular proposals be accepted or that selected transmission facilities be constructed. Similar to the planning requirements of Order No. 890, the Commission requires the establishment of processes to evaluate potential solutions to regional transmission needs, with the input of interested parties and stakeholders. Whether or not public utility transmission providers within a region select a transmission facility in the regional transmission plan for purposes of cost allocation will depend in part on their combined view of whether the transmission facility is an efficient or cost-effective solution to their needs.[307] Moreover, the Commission anticipates that the processes for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation will vary from region to region, just as other aspects of the regional transmission planning processes may vary.

iv. Cost Allocation for Projects Selected in the Regional Transmission Plan for Purposes of Cost Allocation

332. The Commission also requires that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation. More specifically, each public utility transmission provider must participate in a regional transmission planning process that provides that the nonincumbent developer has an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost allocation method or methods. As explained further in section IV.C, the cost of a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region's cost allocation method or methods.

333. In the Proposed Rule, the Commission acknowledged that a proposed transmission project can be modified in the regional transmission planning process as needs and potential solutions are analyzed and, therefore, sought comment on whether to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility. Although the Commission raised this issue in the context of processes of construction rights, similar issues are raised regarding the selection of a transmission facility in the regional transmission plan for purposes of cost allocation.

334. In light of the comments received in response to this aspect of the Proposed Rule, we are concerned that the proposed requirement to identify the most similar project to one initially proposed could conflict with the way potential solutions are evaluated and selected in some regions. For example, a requirement to identify proposals that are ''most similar'' to transmission projects in the regional transmission plan may be meaningless in a region that relies on market proposals or competitive solicitations to identify solutions to the region's needs. In other regions that rely on voluntary construction decisions for transmission facilities in a regional transmission plan, the linking of rights to construct to a determination of similarity may be meaningless. As discussed in the next section, in response to concerns such as these, we have decided not to adopt the proposal that would give a sponsor the federal right to construct and own a transmission facility it sponsored consistent with state or local laws or regulations. Given this change, we do not adopt the proposal to require a mechanism to identify the most similar project to one initially proposed to determine which developer should have the right to construct and own the facility.

335. Instead, we adopt and clarify the requirement that a nonincumbent transmission developer of a transmission facility selected in the regional transmission plan for purposes of cost allocation have the same opportunity as an incumbent transmission developer to allocate the cost of such transmission facilities through a regional cost allocation method or methods. We require that each public utility transmission provider must participate in a regional transmission planning process that makes each transmission facility selected in the regional transmission plan for purposes of regional cost allocation eligible for such cost allocation. In other words, eligibility for regional cost allocation is tied to the transmission facility's selection in the regional transmission plan for purposes of cost allocation and not to a specific sponsor.

336. We also require that public utility transmission providers in a region establish, in consultation with stakeholders, procedures to ensure that all projects are eligible to be considered for selection in the regional transmission plan for purposes of cost allocation. This mechanism could be, for example, a non-discriminatory competitive bidding process. The mechanism a regional planning process implements could also allow the sponsor of a transmission project selected in the regional transmission plan for purposes of cost allocation to use the regional cost allocation method associated with the transmission project. In that case, however, the regional transmission planning process would also need to have a fair and not unduly discriminatory mechanism to grant to an incumbent transmission provider or nonincumbent transmission developer the right to use the regional cost allocation method for unsponsored transmission facilities selected in the regional plan for purposes of cost allocation. There may also be other mechanisms, or combinations of mechanisms, that may comply with our requirements.

337. The Commission declines commenter requests to further define the particular obligations and responsibilities that may flow from selection of a nonincumbent transmission developer's proposal in the regional transmission plan for purposes of cost allocation. Nothing in this Final Rule is intended to change or limit any obligations that would apply to a nonincumbent transmission developer under state or local laws or under RTO or ISO agreements.

v. Rights To Construct and Ongoing Sponsorship

338. The Proposed Rule also sought comment on whether to include two additional features in a framework to implement the elimination of federal rights of first refusal: Whether to require public utility transmission providers to revise their OATTs to contain a regional transmission planning process that

[307] As noted above, for one solution to be chosen over another in the regional transmission planning process, there should be an evaluation of the relative efficiency and cost-effectiveness of each solution. If a nonincumbent transmission developer is unable to demonstrate that its proposal is the most efficient or cost-effective, given all aspects of its proposal, then it is unlikely to be selected as the preferred transmission solution within the regional transmission planning process for purposes of cost allocation.

provides a right to construct and own a transmission facility; and, whether to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that is not selected.[308] The Commission declines to adopt these aspects of the Proposed Rule.

339. In the preceding sections, the Commission adopted a framework in which, upon selection of a transmission facility in a regional transmission plan for purposes of cost allocation, the developer of that transmission facility (whether incumbent or nonincumbent) will have the ability to rely on the relevant cost allocation method or methods within the region should it desire to move forward with its transmission project. Nothing in this Final Rule preempts or limits any obligations or requirements that a nonincumbent transmission developer may be subject to under state or local laws or regulations or under RTO or ISO agreements.

340. With regard to ongoing sponsorship rights, the Commission concludes on balance that granting transmission developers an ongoing right to build sponsored transmission projects could adversely impact the transmission planning process, potentially leading to transmission developers submitting a multitude of possible transmission projects simply to acquire future development rights. The Commission appreciates that not granting such a right causes some risk for transmission developers in disclosing their transmission projects for consideration in the regional transmission planning process. That risk is outweighed, however, by the potentially negative impacts such a rule could have on regional transmission planning.

4. Reliability Compliance Obligations of Transmission Developers

a. Comments Regarding Reliability Obligations

341. PSEG Companies and Indianapolis Power & Light contend that it is unclear how compliance with NERC reliability standards would be managed and whether and to what extent a third-party developer would be responsible for NERC compliance, coordination of outages, and whether it would need to become a member or transmission owner in an RTO. PSEG Companies also assert that third party developers are not regulated by state commissions and are not subject to state law obligations with respect to reliability and safety or state law oversight of their operations. Salt River Project argues that mandatory compliance with NERC reliability standards places added pressure on transmission owners and operators to be involved in every stage of planning, construction, and obligation. It asserts that the Proposed Rule was silent as to whether the proposed rules might work with respect to nonincumbent developers that are subsidized for the project but who then may not be interested or qualified to operate or own the facility, let alone comply with reliability standards. Indianapolis Power & Light also expresses concern that questions will remain regarding whether and to what extent a nonincumbent transmission developer is required to comply with NERC reliability standards. Other commenters respond that incumbent transmission owners and nonincumbent transmission developers are subject to and have to meet the same reliability standards.[309]

b. Commission Determination

342. As discussed in section III.B.3 above, the Commission concludes that potentially increasing the number of asset owners through the elimination of a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, by itself, make it more difficult for system operators to maintain reliability. The Commission acknowledges, however, that a proposed transmission facility's impact on reliability is an important factor that is considered during evaluation of a proposed transmission facility for potential selection. We note that, when a nonincumbent transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it will be required to comply with all applicable reliability obligations, as every other registered entity is required. As part of that process, all entities, incumbent and nonincumbents alike, that are users, owners or operators of the electric bulk power system must register with NERC for performance of applicable reliability functions.

343. However, if there are still concerns regarding the lack of clarity as to when compliance with NERC registration and reliability standards would be triggered, we conclude that the appropriate forum to raise these questions and request clarification is the NERC process.

344. The Commission is sensitive to the concerns of some commenters that contend that existing transmission providers run the risk of violating NERC reliability standards in the event that a nonincumbent transmission developer abandons a transmission facility meant to address a violation. To address such concerns, the Commission clarifies that, if a violation of a NERC reliability standard would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project. Rather, the transmission provider must identify the specific NERC reliability standard(s) that will be violated and submit a NERC mitigation plan to address the violation. Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.

C. Interregional Transmission Coordination[310]

345. This section of the Final Rule adopts several reforms to improve coordination among public utility transmission planners with respect to the coordination of interregional transmission facilities. Specifically, the Commission requires each public utility transmission provider, through its regional transmission planning process, to enhance existing regional transmission planning processes in the following ways.[311] First, the Commission requires the development and implementation of procedures that provide for the sharing of information regarding the respective needs of neighboring transmission planning regions, as well as the identification and joint evaluation by the neighboring transmission planning regions of

[308] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 95.

[309] *E.g.,* City of Santa Clara; Federal Trade Commission; NextEra; Northern California Power Agency; Pattern Transmission; and Western Independent Transmission Group.

[310] We note that our use of the term ''coordination'' with regard to the identification and evaluation of interregional transmission facilities is distinct from the type of coordination of system operations discussed in connection with section 202(a) of the FPA. *See supra* section III.A.2.

[311] In the Proposed Rule, the Commission sometimes referred to the requirements of this section as ''interregional transmission planning''; however, we believe that ''interregional transmission coordination'' better describes what we are requiring in this Final Rule and, therefore, we will refer herein to ''interregional transmission coordination.''

potential interregional transmission facilities that address those needs. Second, to ensure that developers of interregional transmission facilities have an opportunity for their transmission projects to be evaluated, the Commission requires the development and implementation of procedures for neighboring public utility transmission providers to identify and jointly evaluate transmission facilities that are proposed to be located in both regions. Third, to facilitate the joint evaluation of interregional transmission facilities, the Commission requires the exchange of planning data and information between neighboring transmission planning regions at least annually. Finally, to ensure transparency in the implementation of the foregoing requirements, the Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a Web site or e-mail list for the communication of information related to interregional transmission coordination.

346. Through these reforms, the Commission aims to facilitate the identification and evaluation of interregional transmission facilities that may resolve the individual needs of neighboring transmission planning regions more efficiently and cost-effectively. To accomplish these reforms, public utility transmission providers in each pair of transmission planning regions are directed to work through their regional transmission planning processes to develop the same language to be included in each public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the foregoing requirements. Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission planning agreement among the public utility transmission providers within neighboring transmission planning regions that is filed with the Commission.[312]

1. Need for Interregional Transmission Coordination Reform[313]

a. Commission Proposal

347. In Order No. 890, the Commission found that, when transmission providers engage in regional transmission planning, they may identify solutions to regional needs that are more efficient than those that would have been identified if needs and potential solutions were evaluated only independently by each individual transmission provider.[314] In Order No. 890–A, the Commission reiterated that effective regional transmission planning must include coordination among transmission planning regions. To that end, the Commission required public utility transmission providers within each transmission planning region to coordinate as necessary to share data, information, and assumptions to maintain reliability and allow customers to consider resource options that span a region.[315]

348. The Commission noted in the Proposed Rule that, within the Order No. 890 and 890–A framework, transmission providers in certain parts of the country have organized subregional transmission planning groups for the purpose of collectively developing transmission plans for facilities on their combined transmission systems. These subregional transmission plans are then analyzed at a regional level to ensure that, if implemented, they will be simultaneously feasible and meet reliability requirements. The Commission also acknowledged that some neighboring transmission planning regions have undertaken joint transmission planning pursuant to bilateral agreements.[316]

349. However, the October 2009 Notice observed that there are few processes in place to analyze whether alternative interregional solutions more efficiently or effectively would meet the needs identified in individual regional transmission plans. As part of the October 2009 Notice, the Commission posed several questions related to this issue, including whether existing transmission planning processes are adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers. The Commission also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.

350. In light of the comments received on this issue, the Commission in the Proposed Rule expressed concern that the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential. The Commission noted that, in the few years since the issuance of Order No. 890, interest in multiregional transmission facilities has grown significantly.[317] Therefore, the Commission proposed reforms intended to improve coordination between neighboring transmission planning regions with respect to the evaluation of transmission facilities that are proposed to be located in both regions, as well as other possible interregional transmission facilities, to determine if such facilities address the needs of the transmission planning regions more efficiently or cost-effectively.[318]

b. Comments

351. Many commenters agree that there is a need to increase coordination in interregional transmission planning,[319] and identified a range of deficiencies in and opportunities for enhancement of existing interregional transmission coordination efforts. Several commenters state that a more defined and coordinated interregional transmission planning process is

[312] We discuss the filing requirements for the same language to be included in each public utility transmission provider's OATT that describes the procedures that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements as well as for any interregional transmission coordination agreements in the compliance section below. *See* discussion *infra* section III.C.3.e. of this Final Rule.

[313] Legal authority issues associated with the interregional transmission coordination reforms described herein are addressed in the discussion above concerning regional transmission planning. *See* discussion *supra* section III.A.2. of this Final Rule.

[314] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

[315] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 226.

[316] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 103.

[317] The Commission cited two such recent multiregional projects. *Id.* n.46 (citing *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281 (2009); *Green Power Express LP,* 127 FERC ¶ 61,031 (2009)).

[318] *Id.* P 112–113.

[319] *E.g.,* AEP; Allegheny Energy Companies; AWEA; CapX2020 Utilities; Clean Line; Duke; East Texas Cooperatives; Edison Electric Institute; Energy Future Coalition; Environmental Defense Fund; Exelon; Federal Trade Commission; First Energy Service Company; Integrys; ISO New England; ITC Companies; Kansas City Power & Light and KCP&L Greater Missouri; LS Power; Massachusetts Departments; MidAmerican; MISO; MISO Transmission Owners; Minnesota PUC and Minnesota Office of Energy Security; National Grid; Natural Resources Defense Council; NEPOOL; New York ISO; NextEra; Northeast Utilities; Old Dominion; Organization of MISO States; Pattern Transmission; Pennsylvania PUC; PHI Companies; Pioneer Transmission; Powerex; PSEG Companies; PUC of Nevada; San Diego Gas & Electric; Sonoran Institute; Sunflower and Mid-Kansas; Transmission Access Policy Study Group; Vermont Electric; Westar; Wilderness Society and Western Resource Advocates; WIRES; and Wisconsin Electric Power Company.

necessary. For example, AEP, joined by Integrys, contends that utility and regional transmission planning efforts have a limited geographic perspective and do not consider the benefits associated with interregional transmission projects in neighboring regions. Boundless Energy and Sea Breeze state that in the absence of RTOs and ISOs, and particularly in WECC, interregional transmission planning is ineffective, overly costly, and focuses on individual transmission projects with no relationship to the grid as a whole network or a smart grid.

352. Other commenters argue that there is no coordinated process between regions with respect to evaluating interregional transmission projects.[320] AEP and MidAmerican specify that the lack of a coordinated process between transmission planning regions creates hurdles for projects (especially proposed extra high voltage facilities) that are unreasonably higher than those faced by intraregional transmission projects. MidAmerican contends that different regions have different planning protocols and rules for project evaluation and justification, and focus too narrowly on planning criteria that are limited to reliability, generator interconnection, and economic congestion relief to demonstrate the need for a project. It states that many transmission planning regions do not have joint planning protocols or other tariff authority under which an interregional project could be approved based on the total benefits that it provides to the planning regions; and that there is a lack of coordinated planning to identify the most economically efficient solutions. Transmission Dependent Utility Systems state that the ultimate objective of the Final Rule should be the development of a regional transmission plan that jointly optimizes solutions for transmission across the regions to allow access to economically-priced energy by all transmission providers and customers to best serve their native loads. 26 Public Interest Organizations state that without interregional coordination of planning assumptions and procedures, it may not be possible to develop regional transmission plans that the Commission can rely on to determine whether rates are just and reasonable.

353. Some other commenters state that improved interregional transmission coordination would result in a more orderly and timely transmission planning process.[321] Pioneer Transmission indicates that improved interregional transmission planning would require planning regions to adopt broader planning goals and objectives, plan transmission and generation in a coordinated and cohesive fashion, and recognize that the benefits of interregional transmission projects will multiply and that their beneficiaries often expand over time.

354. Several commenters also discuss the positive impacts that the proposed interregional transmission planning requirements would have on renewable resources. For example, some state that these requirements would facilitate access to renewable energy and help meet state, federal and other renewable energy goals.[322] Pattern Transmission indicates that unless a formal interregional planning process is required, approval of transmission projects needed to allow load to access renewable resources will be difficult, particularly for remotely-located resources. Wind Coalition states that without interregional planning, location-constrained resources located in one region that could be cost-effectively accessed to serve the needs of an adjacent, or even more distant region, will not be available or may be accessed through a more expensive and less efficient transmission solution than would be possible with interregional transmission planning.

355. Some commenters argue that seams issues have prevented efficient use of existing transmission infrastructure and adequate consideration of the needs of load-serving entities at the seams.[323] Several commenters cite difficulties they have had in the MISO and PJM, Entergy and SPP, PJM and New York ISO, and Pacific Northwest regions.[324] For example, East Texas Cooperatives state a lack of coordination between SPP and Entergy has hindered its ability to obtain network service for a new generating plant. Specifically, East Texas Cooperatives state that in 2009 they submitted a request to SPP for 335 MW of network service sourcing and sinking in SPP to access the Harrison County generating plant. When studying the request, SPP determined that it may cause impacts on Entergy's system. After multiple iterations of the SPP Aggregate Study Process and two Affected System Analysis were conducted, the Entergy system identified $30.7 million of upgrades necessary to facilitate the request, the cost of which were to be directly assigned to East Texas Cooperatives. East Texas Cooperatives identified several potential issues in the SPP and Entergy studies that appeared to stem, at least in part, from a lack of queue coordination between Entergy and SPP. East Texas Cooperatives state that after significant effort on their part and additional study costs being incurred, which may not have been necessary with better coordination between Entergy and SPP, the cost of the necessary upgrades on the Entergy system was dramatically reduced. However, East Texas Cooperatives state that errors in SPP's planning studies and a lack of coordination between SPP and Entergy in addressing East Texas Cooperatives' network service request, resulted in a long delay in securing the necessary financing for the Harrison County project.

356. Similarly, ITC Companies state that it has been difficult to move forward on its Green Power Express project because there is no applicable planning process for projects that extend beyond the boundaries of a single RTO. Exelon states that its experience on the seam between MISO and PJM supports the contention that mandatory interregional planning is needed at this time. For instance, Exelon cites issues in studying and building transmission projects identified in the MISO's Regional Generation Outlet Study as necessary to deliver 35 GW of wind energy to load centers in the MISO. Exelon states that several of the projects are located in PJM, but will not be studied further by the MISO because MISO states that it has no authority to order its members or PJM members to build transmission on PJM's system. In addition, Exelon states that current coordination protocols between the MISO and PJM are failing to prevent increased congestion in PJM, resulting in deteriorating operations at the seam such as increased transmission loading relief (TLR) events on the Commonwealth Edison system. PJM, however, disputes Exelon's assertions regarding both the cause and the total number of TLR events on the Commonwealth Edison system.

357. PSEG Companies recommend that where there is evidence of

[320] *E.g.,* East Texas Cooperatives; AEP; Kansas City Power & Light and KCP&L Greater Missouri; Anbaric and PowerBridge; Edison Electric Institute; MISO Transmission Owners; TDU Systems; AWEA; and PSEG Companies.

[321] *E.g.,* First Wind; Solar Energy Industries; and Large-scale Solar.

[322] *E.g.,* Edison Electric Institute; AWEA; Clean Line; American Transmission; and Solar Energy Industries and Large-scale Solar.

[323] *E.g.,* AEP; Anbaric and PowerBridge; Connecticut & Rhode Island Commissions; East Texas Cooperatives; Edison Electric Institute; Energy Consulting Group; MISO Transmission Owners; Northeast Utilities; and Omaha Public Power District.

[324] *E.g.,* Pennsylvania PUC; MidAmerican; Exelon; East Texas Cooperatives; PSEG Companies; and Powerex.

significant seams issues that affect operations, the Commission should require that the affected planning regions: (1) coordinate the planning of their systems, including sharing information needed to forecast, measure, and monitor impacts; and (2) form an agreement to address how the costs associated with cross-border impacts will be allocated that incorporates the ''beneficiary pays'' approach. Pennsylvania PUC states that the Commission's proposed interregional transmission planning requirements may help to improve interregional operational efficiency between RTOs.

358. Organization of MISO States and Pattern Transmission discuss the effect of improved interregional coordination between RTO and non-RTO regions. Organization of MISO States notes that the proposed requirements would enhance the incorporation of non-RTO regions into interregional transmission planning processes. According to Pattern Transmission, interregional transmission planning is particularly important in non-RTO and non-ISO regions, where the lack of a structured regional transmission planning process effectively restricts transmission development by nonincumbent developers to merchant transmission developers.

359. Transmission Dependent Utility Systems urge the Commission to adopt the proposed interregional transmission planning reforms without delay as they are necessary to promote cost-effective interregional transmission planning and to remedy the unduly discriminatory exclusion of transmission customers that are load-serving entities from these activities. They assert that transmission providers have little incentive to develop transmission that would allow competing suppliers to serve customers and that in many regions, interregional transmission planning efforts are either nonexistent or are often implemented through bilateral agreements that provide no opportunity for active participation by transmission customers that are load-serving entities or other stakeholders.

360. Several commenters stress that the Commission's actions in this proceeding must not interfere with the ARRA-funded transmission planning initiatives.[325] Allegheny Energy Companies believe in the potential success of the ARRA-funded process. They state that the ARRA-funded interconnectionwide transmission planning initiatives may develop into a potential model for an open, interconnectionwide transmission planning process and in effect could help resolve some of the planning issues currently being encountered. Western Area Power Administration urges the Commission to consider the positive developments associated with the implementation of these initiatives while developing any Final Rule.

361. Some commenters argue that interregional transmission planning reforms are needed notwithstanding the ARRA-funded interconnectionwide transmission planning initiatives.[326] SPP states that the ARRA-funded process will not ensure that the most cost-effective solutions are implemented across planning regions or the entire interconnection. Transmission Dependent Utility Systems also contend that the ARRA-funded process does not address short-range needs for interregional projects and may have too wide of a geographic scope to conduct the bottom-up planning necessary to ensure that the needs of load-serving entities are met. AEP encourages the Commission to provide as much direction as possible to the planning authorities to ensure that the ARRA initiatives accomplish more than the cumulative assembly of the isolated plans of each region and planning entity.

362. Conversely, other commenters suggest that the Commission postpone imposing new requirements until after the ARRA-funded interconnection-wide transmission planning process is complete.[327] For example, Southwest Area Transmission Sub-Regional Planning Group encourages the Commission to support existing planning activities, postponing the proposal for additional requirements until after the ARRA-funded interconnectionwide transmission planning initiatives are complete. ColumbiaGrid and ISO New England argue that their transmission planning processes already comply with the Commission's proposed requirements. The New England Transmission Owners support the Commission's interregional transmission planning objectives, but urge the Commission to give the ISO New England's existing interregional transmission planning process time to mature before imposing any new or additional requirements. PHI Companies argue that the Commission should require that existing interregional planning processes that meet the Commission's articulated principles be followed whenever the objectives of one region have the potential to impose burdens or costs on another region.

363. Other commenters oppose the Commission's proposed interregional transmission planning requirements, arguing they are unnecessary[328] or premature.[329] In particular, several commenters state that existing transmission planning processes in their regions (West, Southeast, Midwest) have led to significant progress and that there is no need for mandating that regions create interregional transmission planning agreements.[330] For example, Southern Companies state that there already is an institution in place to provide interregional coordination in the Eastern Interconnection, namely the Eastern Interconnection Planning Collaborative. Salt River Project similarly states that it participates in robust and effective planning activities in the West, and provides an inventory of projects, including interregional lines that are being built as a result of coordination between regional and subregional planning groups. Southern Companies note that the Commission's proposed interregional transmission planning requirements are unnecessary as the deficiencies alleged by the Commission in the Proposed Rule are not applicable in the Southeast. Organization of MISO States expresses its view that the Commission should give the interconnectionwide Eastern Interconnection States Planning Council planning process some time to work before requiring the filing of any bi-regional interregional transmission planning agreements.

364. Salt River Project and Southwest Area Transmission contend that the proposed requirements are premature because the Commission did not provide specific examples of deficiencies and lack of coordination in the transmission planning process that support the need for the proposed requirements. They recommend that the Commission undertake a comprehensive

[325] *E.g.,* Indianapolis Power & Light; NARUC; PHI Companies; Pennsylvania PUC; PSC of Wisconsin; SPP; and Transmission Access Policy Study Group.

[326] *E.g.,* SPP; Minnesota PUC and Minnesota Office of Energy Security; AEP; and Transmission Dependent Utility Systems.

[327] *E.g.,* Southwest Area Transmission Sub-Regional Planning Group; APPA; and Xcel.

[328] *E.g.,* California ISO; ColumbiaGrid; Indianapolis Power & Light; National Rural Electric Coops; Southern Companies; and Washington Utilities and Transportation Commission.

[329] *E.g.,* Georgia Transmission Corporation; Salt River Project; and Southwest Area Transmission Sub-Regional Planning Group.

[330] *E.g.,* Salt River Project; Southwest Area Transmission Sub-Regional Planning Group; Xcel; California Commissions; San Diego Gas & Electric; NEPOOL; Northeast Utilities; New England Transmission Owners; Southern Companies; Washington Utilities and Transportation Commission; and Indianapolis Power & Light.

and thorough inventory of existing planning processes and then use the demonstrable outcomes of these processes to identify any real barriers that would merit new rules or regulations. National Rural Electric Coops, Indianapolis Power and Light, and Transmission Agency of Northern California contend, in whole or part, that the Commission should pursue only additional reforms that address specific problems identified in the record from this proceeding, that mandatory coordination should occur on an as-needed basis where such efforts are likely to lead to substantial transmission development, and that any further reforms be targeted to specific problems.

365. Some commenters suggest that the Commission should allow Order No. 890 processes to develop further before imposing new interregional coordination requirements.[331] Xcel acknowledges the need for interregional planning and cost allocation mechanisms to support public policy mandates, but recommends that the Commission allow current voluntary interregional planning and cost allocation discussions to continue, rather than mandate the development of interregional agreements within a specified time frame.

366. Similarly, several commenters contend that interregional coordination should be voluntary. Ad Hoc Coalition of Southeastern Utilities and Bonneville Power contend that the Commission should permit parties to pursue voluntary interregional transmission planning agreements. Ad Hoc Coalition of Southeastern Utilities states that it supports voluntary efforts of regional transmission processes to address facilities located in multiple regions. Similarly, North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should be voluntary. Bonneville Power states that the Commission has not demonstrated that the voluntary approach does not work in the Pacific Northwest or that it is not just and reasonable or that it is unduly discriminatory or preferential. It recommends that if the Commission mandates interregional transmission planning agreements, it should permit parties the discretion to pursue voluntary agreements for interregional planning in general, as well as for specific projects. Further, California ISO points to successful voluntary coordination efforts in the West by WECC and California Transmission Planning Group. California PUC, in its reply comments, supports California ISO's and Bonneville Power's views.

367. Other reply commenters disagree with these arguments. 26 Public Interest Organizations respond that the Commission is obligated under the FPA to ensure that changing system needs (such as state renewable portfolio standards and new federal environmental rules) and the consequences for systems outside of the RTO's footprint (such as loop flow) are justly and reasonably addressed, which requires interregional coordination. WIRES replies that interregional planning must be made mandatory and subject to stronger Commission oversight and participation. WIRES states that experience demonstrates that, left to the voluntary cooperation of the parties, the transmission network will not be integrated as effectively as it could be, reliability and resource diversity will suffer, and seams and congestion issues will be unresolved.

c. Commission Determination

368. The Commission concludes that implementation of further reforms in the area of interregional transmission coordination activities are necessary at this time. As the Commission stated in the Proposed Rule, in the absence of coordination between transmission planning regions, public utility transmission providers may be unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes, potentially including interregional transmission facilities. Clear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans.

369. Specifically, we agree with commenters, such as AEP, that the transmission planning requirements of Order No. 890 are too narrowly focused geographically and fail to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions. Our decision also is influenced by those commenters that cite seams issues or difficulties they have encountered in coordinating the development of transmission facilities across the regions, including between RTOs and ISOs, as well as between an RTO or ISO and non-RTO or ISO region and among non-RTO regions. We are persuaded by those commenters who argue that additional interregional transmission coordination requirements would facilitate consideration of transmission needs driven by Public Policy Requirements by enabling the evaluation of interregional transmission facilities that may address those needs more efficiently or cost-effectively. We agree with Transmission Dependent Utility Systems' comments that interregional transmission coordination promotes cost-effective transmission development and facilitates transmission customer participation in interregional transmission coordination efforts.

370. Given the clear need for reform of existing interregional transmission coordination practices, we are not persuaded by arguments contending that reform is not necessary or is premature. While we recognize that significant progress with respect to the development of open and transparent transmission planning processes has been made around the country, the existing transmission planning processes nevertheless do not adequately provide for the evaluation of proposed interregional transmission facilities or the identification of interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Because such interregional transmission coordination helps to ensure that rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential by facilitating more efficient or cost-effective transmission infrastructure development, we conclude that the interregional transmission coordination reforms adopted in this Final Rule are necessary and should not be delayed.

371. Similarly, while we have considered the positive developments associated with the ARRA-funded transmission planning initiatives, we nevertheless agree with commenters who argue that the Commission should not postpone its proposed interregional transmission coordination reforms on account of these initiatives. While the ARRA-funded transmission planning initiatives represent a significant advancement in interconnectionwide transmission scenario analysis, they do not specifically provide for the ongoing coordination in the evaluation of interregional transmission facilities, which we conclude is necessary to ensure that rates, terms, and conditions of jurisdictional services are just and

[331] *E.g.*, Washington Utilities and Transportation Commission; Georgia Transmission Corporation; and Xcel.

reasonable and not unduly discriminatory or preferential. As requested by commenters, however, we have extended the compliance deadline for the interregional coordination requirements of this Final Rule, as discussed in section V.A below. We encourage public utility transmission providers to continue their participation in these efforts and to explore opportunities to use the valuable information these efforts provide in their regional transmission planning and interregional transmission coordination efforts. We reiterate our intent to build upon, and not interfere with, the ARRA-funded transmission planning initiatives in this Final Rule.

372. With regard to commenters' contentions that their existing interregional transmission coordination efforts already comply with the Proposed Rule's provisions or need more time to mature, we acknowledge that some transmission planning regions already may engage in interregional transmission coordination efforts that satisfy some of the requirements discussed below or are developing such efforts. The Commission is acting in this Final Rule to establish a minimum set of requirements that apply to all public utility transmission providers. If a public utility transmission provider believes that it participates in a regional transmission planning process that fulfills the interregional transmission coordination requirements adopted in this Final Rule, it may describe in its compliance filing how such participation complies with the requirements of this Final Rule.

373. We therefore disagree that the Commission should undertake additional investigation of the need for interregional coordination procedures or require them only on a case-by-case basis. The record in this proceeding is adequate to support our conclusion that the existing requirements of Order No. 890 are too narrowly focused geographically. Coordination of transmission planning activities by neighboring transmission planning regions will increase opportunities to identify interregional transmission facilities that address the needs of those regions more efficiently or cost-effectively. We thus see no need to adopt a case-by-case approach to our requirements. We conclude that the interregional coordination obligations implemented in this Final Rule are necessary to establish a minimum set of requirements that are applicable to all public utility transmission providers.

2. Interregional Transmission Coordination Requirements

a. Interregional Transmission Coordination Procedures

i. Commission Proposal

374. In the Proposed Rule, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to enter into agreements that include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed that could address transmission needs more efficiently than separate intraregional facilities.[332] While acknowledging that every transmission planning agreement could be tailored to best fit the needs of the transmission planning regions entering into the agreement, the Commission proposed that each public utility transmission provider ensure that certain elements are included in each agreement.

375. Specifically, the Commission proposed that an interregional transmission planning agreement must include the following elements: (1) A commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities (Coordination); (2) an agreement to exchange at least annually planning data and information (Data Exchange); (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions (Joint Evaluation); and (4) a commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated transmission planning process (Transparency).

376. With respect to the third proposed element, the Commission proposed that the transmission developer of a transmission project that would be located in two neighboring transmission planning regions must first propose its transmission project in the transmission planning process of each of those transmission planning regions. The Commission further proposed that such a submission would trigger a procedure established by the interregional transmission planning agreement, under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed transmission project. The Commission proposed that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, the Commission proposed that inclusion of the interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an interregional cost allocation method that satisfies the cost allocation principles set forth in the Proposed Rule.

ii. Comments

377. American Transmission supports requiring regions to make a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently than separate intraregional facilities. However, American Transmission also recommends that the Commission require public utility transmission providers to specifically describe the process by which their planning regions will identify such interregional transmission facilities. East Texas Cooperatives suggest that the Commission clarify that it requires more than simple coordination (*i.e.*, the sharing of information and plans), but also the establishment of an interregional transmission planning process intended to address and resolve seams issues.

378. Several commenters request that the Commission provide more detailed guidance on the interregional transmission planning agreements.[333] MISO Transmission Owners similarly request that the Commission clarify its specific expectations for interregional coordination. SPP recommends that the Final Rule provide detailed guidance concerning the requirements for interregional transmission planning, including the goals and objectives of interregional transmission planning. Powerex states that the Commission should require each interregional transmission planning agreement to include a set of interregional planning goals that are concrete and outcome-

[332] The Commission discusses in subsection 3e below comments in response to the proposal for interregional transmission coordination activities to be memorialized in an agreement executed by multiple public utility transmission providers.

[333] *E.g.*, 26 Public Interest Organizations; MISO Transmission Owners; SPP; and Sunflower and Mid-Kansas.

based and that directly address the reliability problems that reduce efficiency. ITC Companies state that interregional transmission planning agreements should include the key criteria to be considered in the interregional planning process, based on the planning principles, and the cost allocation method that would apply to approved interregional projects.[334]

379. Old Dominion recommends that the Commission require public utility transmission providers and interregional planning entities, such as the Eastern Interconnection Planning Collaborative, to adopt transmission planning processes that: (1) Identify the needs of multiple transmission systems based on scenario planning using a long-term planning horizon (*e.g.*, 15 to 20 years); (2) conduct various scenario analyses to identify the projects that best address reliability, economic, or demand response concerns; and (3) allow developers to compete to provide the ''best'' solution.

380. Some commenters support a more robust interregional transmission planning process than the interregional coordination requirements set forth in the Proposed Rule. For example, Energy Future Coalition states the interregional transmission planning process should include a rigorous and transparent analysis of a comprehensive set of considerations and alternatives and provide for ''right-sizing'' facilities to ensure the best possible use of existing corridors and minimize environmental impacts from new corridors.

381. A few commenters recommend that the Commission require interregional transmission planning processes to comply with the Order No. 890 planning principles.[335] Transmission Dependent Utility Systems contend that subjecting interregional transmission planning processes to the Order No. 890 planning principles would alleviate concerns about the limited size of some Order No. 890-compliant planning regions, which arose due to the lack of an opportunity for load-serving entities to participate in planning across seams, and would ensure that the most cost-effective solutions to constraints associated with seams are pursued. Old Dominion states that requiring interregional transmission planning processes to comply with the Order No. 890 planning principles would ensure that information will flow between the regional and interregional transmission planning processes, so that stakeholders will have the information necessary to offer meaningful input at the interregional level and to inform discussions at the regional levels.

382. Energy Consulting Group states that transmission owners should be required to develop the transmission upgrades and expansions identified in the wide-area planning process within a mandated time frame. NextEra states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes interregional transmission facilities identified through the planning process. Boundless Energy and Sea Breeze contend that the Commission should strengthen interregional transmission planning processes by requiring implementation of interregional transmission plans and an implementing authority. MidAmerican expresses concern that proposed element 1 does not describe how the Commission intends neighboring planning regions to move those interregional projects identified towards construction, and recommends that the Commission require the identified interregional facilities to be included in local and regional transmission plans. Similarly, National Grid recommends that the Commission require consideration of procedures for adopting into regional plans any transmission upgrade identified as part of an interregional coordination process.

383. Southwest Area Transmission Sub-Regional Planning Group, however, states that the Commission should clarify that interconnectionwide, regional, and interregional planning groups are not decision-making entities with the authority to direct developers or load-serving entities to develop any project. National Grid asks the Commission not to require the formation of new interregional planning entities, especially where interregional planning efforts are already underway.

384. NextEra also states that the Commission should require the interregional transmission planning process to result in an interregional transmission plan that includes longer-term objectives that have not yet resulted in proposals for specific facilities. Similarly, California Commissions state that plans should contain conceptual elements that have yet to materialize as specific transmission projects and contingent elements that may be needed under certain future scenarios so that a plan can evolve over time.

385. Solar Energy Industries and Large-scale Solar and Anbaric and PowerBridge urge the Commission to impose stronger requirements for interregional coordination for public policy and renewable energy projects. MidAmerican asks that the Commission clarify that consideration of public policy requirements is not limited to local and regional transmission planning processes but should be extended to interregional transmission coordination as well.

386. On the other hand, Energy Consulting Group contends that interregional transmission planning should provide an incentive for development of transmission facilities that provide access to economic generation resources that minimize power costs, not act as an instrument of public policy. Energy Consulting Group also states that it is not clear that the proposed transmission planning processes will have a mechanism to address transmission service requests, and that a process for addressing such requests should be added to wide-area planning.

387. ITC Companies contend that interregional coordination should assure equal consideration for all drivers of transmission needs, including reliability, generator interconnection, and public policy requirements. National Grid requests that the Commission require interregional transmission planning efforts to consider transmission upgrades that could provide economic benefits to consumers in multiple regions and upgrades or modified operating practices that could result in more efficient use of the existing transmission system in addition to those transmission facilities needed to maintain reliability. Powerex states that the Final Rule should establish policies that encourage transmission customers to continue to purchase and invest in long-term transmission and that the Commission should ensure that it is sending proper signals for long-term investments in transmission by rejecting policies that erode the existing rights of firm transmission customers that have already made long-term investments in transmission service.

388. Organization of MISO States urges the Commission to encourage transmission planning regions to coordinate on issues besides transmission planning and cost allocation, such as interconnection and operational issues.

389. North Carolina Agencies state that coordination among regions, as well as within a broadly defined region, should complement, rather than

[334] The cost allocation method that would apply to selected interregional transmission facilities is addressed in the cost allocation section below. *See* discussion *supra* section IV.E. of this Final Rule.

[335] *E.g.,* East Texas Cooperatives; ITC Companies; Old Dominion; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

substitute for, local and narrower regional planning processes. NEPOOL and Northeast Utilities state that the Proposed Rule's provisions, which reflect a ''bottom up'' planning approach, should be reflected in any Final Rule. Other commenters also support a ''bottom up'' approach to interregional transmission planning.[336]

390. Other commenters urge the Commission to ensure that the Final Rule does not infringe on state authority. California Commissions emphasize that rules pertaining to interregional transmission planning agreements and the resulting coordinated planning process must not diminish state control by shifting decision-making to the Commission and that states should be directly involved in the development of interregional transmission planning agreements and should have a strong role in their implementation. NARUC asserts that the interregional transmission planning process must continue to respect the role of state commissions in reviewing and guiding the planning process and the role of state authorities in ultimately siting any transmission lines.

391. Several commenters request that the Commission oversee the development and implementation of interregional transmission planning agreements and/or monitor the progress of interregional planning efforts.[337] For example, Organization of MISO States suggests that the Commission require an accountability and oversight element in interregional transmission planning agreements to ensure that such agreements are implemented as intended, perhaps utilizing the expertise of state commissions. American Transmission and MISO Transmission Owners state that public utility transmission providers and their stakeholders should be required to conduct periodic reviews of the effectiveness of their interregional transmission planning efforts and file informational reports with the Commission.

392. Federal Trade Commission acknowledges that the Commission's proposed interregional transmission planning requirements would require market participants that may be competitors to collaborate with each other in transmission planning, construction, ownership, and operation, but states that participants in the interregional transmission planning process should not view the antitrust laws as an impediment to their participation.

iii. Commission Determination

393. To remedy the potential for unjust and unreasonable rates for public utility transmission providers' customers, we adopt the interregional transmission coordination requirements discussed below. These interregional transmission coordination requirements obligate public utility transmission providers to identify and jointly evaluate interregional transmission facilities that may more efficiently or cost-effectively address the individual needs identified in their respective local and regional transmission planning processes.

394. In the Proposed Rule, the Commission set forth its proposed interregional transmission coordination requirements in the form of four elements to be included in an interregional transmission planning agreement. After reviewing the comments concerning interregional transmission coordination received in this proceeding, we find that these four elements are so extensively interconnected that it would be inappropriate to require that they be addressed as distinct elements, as was proposed in the Proposed Rule. Instead, we believe that these four elements are better represented as characteristics of interregional transmission coordination. Specifically, two of the proposed elements—Coordination and Joint Evaluation—embody the purpose of interregional transmission coordination: to coordinate and share the results of regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities and to jointly evaluate such facilities, as well as to jointly evaluate those transmission facilities that are proposed to be located in more than one transmission planning region. The other two elements—Data Exchange and Transparency—are more appropriately described as part of the procedures through which effective interregional transmission coordination is implemented.

395. Thus, the framework in which we present these requirements differs from that of the Proposed Rule. This Final Rule lays out the objectives of interregional transmission coordination followed by a discussion of the mechanics of interregional transmission coordination instead of four required elements. Here we address the requirements for interregional transmission coordination, the entities between which interregional transmission coordination must occur, and the transmission facilities to which the interregional transmission coordination requirements apply. Hence the discussion of Coordination and Joint Evaluation is here. We address in other sections below the mechanics of implementation, including a discussion of the procedures for joint evaluation, requirements for data exchange, transparency, stakeholder participation, and the required revisions to the OATT.

396. The Commission requires each public utility transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Through adoption of this requirement, the Commission intends that neighboring transmission planning regions will enhance their existing regional transmission planning processes to provide for: (1) The sharing of information regarding the respective needs of each region, and potential solutions to those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs.[338] By requiring public utility transmission providers to undertake such interregional transmission coordination activities, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are more efficient or cost-effective solutions to meeting transmission planning region's needs.

397. In response to the Proposed Rule, several commenters seek clarification from the Commission as to whether, for example, the Commission intends the formation of a new interregional transmission planning process or that certain types of facilities or objectives should be the focus of interregional transmission coordination. With the exception of the requirements for

[336] *E.g.*, Allegheny Energy Companies; East Texas Cooperatives; and ISO New England.

[337] *E.g.*, Energy Future Coalition; Organization of MISO States; Transmission Dependent Utility Systems; and AWEA.

[338] The same language must be included in each public utility transmission provider's OATT that describes the processes that a particular pair of transmission planning regions will use to satisfy the interregional transmission coordination requirements of this Final Rule. The filing requirements concerning this same language are discussed in the compliance section below. *See* discussion *infra* section VI.A. of this Final Rule.

implementing interregional transmission coordination discussed herein, the Commission declines at this time to impose specific obligations as to how neighboring transmission planning regions must share information regarding their needs, and potential solutions to those needs, or identify and jointly evaluate interregional transmission alternatives to those regional needs, as well as proposed interregional transmission facilities. Thus, we also decline to require the use of specific planning horizons or the performance of particular scenario analyses. While we appreciate commenters' desire for additional clarity on this point, the Commission believes it is appropriate to leave to the transmission planning regions in the first instance adequate discretion to allow for the development and implementation of interregional transmission coordination procedures that suit the needs of the neighboring transmission planning regions. In light of the varying approaches to transmission planning that are currently used by transmission planning regions across the country, providing further guidance at this time could inadvertently impose restrictions that are not appropriate for a particular transmission planning region.

398. However, we clarify in response to East Texas Cooperatives that the interregional transmission coordination requirements adopted do require that public utility transmission providers do more than simply commit to share their regional transmission plans and other transmission planning information. To comply with the requirements in this Final Rule, each public utility transmission provider, through its regional transmission planning process, must develop and implement additional procedures that provide for the sharing of information regarding the respective needs of each neighboring transmission planning region, and potential solutions to those needs, as well as the identification and joint evaluation of interregional transmission alternatives to those regional needs by the neighboring transmission planning regions. On compliance, public utility transmission providers must describe the methods by which they will identify and evaluate interregional transmission facilities. While the Commission does not require any particular type of studies to be conducted, this Final Rule requires public utility transmission providers in neighboring transmission planning regions to jointly identify and evaluate whether interregional transmission facilities are more efficient or cost-effective than regional transmission facilities. Accordingly, the Commission requires that the compliance filing by public utility transmission providers in neighboring planning regions include a description of the type of transmission studies that will be conducted to evaluate conditions on their neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities.

399. We decline to adopt the recommendations of those commenters that suggest that the Commission adopt a more robust, formalized interregional transmission planning process than the interregional transmission coordination requirements in the Proposed Rule, such as an interregional transmission coordination process that complies with the Order No. 890 transmission planning principles or that produces an interregional transmission plan. We clarify here that the interregional transmission coordination requirements that we adopt do not require formation of interregional transmission planning entities or creation of a distinct interregional transmission planning process to produce an interregional transmission plan. Rather, our requirement is for public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs more efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions. To the extent that public utility transmission providers wish to participate in processes that lead to the development of interregional transmission plans, they may do so and, as relevant, rely on such processes to comply with the requirements of this Final Rule.

400. While we acknowledge MidAmerican's concern that the Commission does not specify how interregional transmission facilities will be moved toward construction, we note that in the Proposed Rule, the Commission stated that, consistent with Order No. 890, the proposed regional transmission planning obligations do not address or dictate which investments identified in a transmission plan should be undertaken by public utility transmission providers.[339] We affirm that statement, and further note that Order No. 890 already requires that public utility transmission providers make available information regarding the status of transmission upgrades identified in their regional transmission plans in addition to the underlying transmission plans and related transmission studies.[340] The Commission made clear in Order No. 890–A that transmission providers must make available to other stakeholders information regarding the progress and construction of transmission upgrades and transmission facilities.[341] To the extent neighboring transmission planning regions identify interregional transmission facilities of mutual benefit and have such transmission facilities in their individual regional transmission plans, these informational requirements will apply to the portions of the interregional transmission facilities within each of the individual region's transmission plans. We decline to require, as suggested by MidAmerican and National Grid, that every interregional transmission facility that is evaluated through the interregional transmission coordination procedures automatically be selected in a regional transmission plan for purposes of cost allocation. However, as discussed below, an interregional transmission facility must be selected in both of the relevant regional transmission plans for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to an interregional cost allocation method required under this Final Rule. Rather, we expect that information exchanged during the interregional coordination effort should inform discussions at the regional and local transmission planning level.

401. Moreover, in response to commenters, this Final Rule neither requires nor precludes longer-term interregional transmission planning, including the identification of conceptual or contingent elements,[342] the consideration of transmission needs driven by Public Policy Requirements,[343] or the evaluation of economic considerations.[344] Whether and how to address these issues with regard to interregional transmission facilities is a matter for public utility transmission providers, through their regional transmission planning processes, to resolve in the development of compliance proposals. However, the

[339] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.59 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438).

[340] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472.

[341] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 202.

[342] *See* California Commission.

[343] *See* MidAmerican.

[344] *See* Energy Consulting Group.

Commission agrees with North Carolina Agencies that interregional transmission coordination should complement local and regional transmission planning processes, and should not substitute for these processes. Consistent with the implementation requirements for interregional transmission coordination procedures discussed in section III.C.3.a. below, we clarify that interregional transmission coordination may follow a ''bottom up'' approach. In response to Energy Consulting Group, we neither require nor prohibit consideration by neighboring transmission planning regions of requests for transmission service or upgrades within the interregional transmission coordination procedures required in this Final Rule.

402. With respect to commenters' assertion that this Final Rule should not infringe on state authority, we emphasize here that the interregional transmission coordination requirements are not intended to infringe on state authority. We acknowledge the vital role that state agencies play in transmission planning and their authority to site transmission facilities. We strongly encourage state agencies to be involved in the development and implementation of the interregional transmission coordination procedures necessary to satisfy the interregional transmission coordination requirements adopted herein.

403. In response to commenters' requests that we monitor the implementation of the interregional transmission coordination requirements adopted in this Final Rule and the progress of interregional transmission coordination efforts, although the Commission believes that Commission oversight of compliance with this Final Rule and assessment of the adequacy of its measures is appropriate, the Commission does not intend to monitor coordination efforts so closely as to intrude in the interregional transmission coordination activities. It is not necessary for the Commission to decide the exact level of its monitoring at this time.

404. We also decline to require public utility transmission providers and their stakeholders to conduct periodic reviews of the effectiveness of their interregional transmission coordination efforts and file information reports with us, as suggested by American Transmission and MISO Transmission Owners. However, we do encourage such reviews. We also note that parties may utilize the dispute resolution provisions of the relevant public utility transmission provider's OATT or file a complaint with the Commission if they find that the interregional transmission coordination procedures described in a public utility transmission provider's OATT are not being implemented properly.

b. Geographic Scope of Interregional Transmission Coordination

i. Commission Proposal

405. As noted above, the Commission proposed to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues. The Commission noted that this does not require a public utility transmission provider to coordinate with a neighboring transmission planning region in another interconnection. However, the Commission also encouraged public utility transmission providers to explore possible multilateral interregional transmission coordination processes among several, or even all, transmission planning regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives.[345] The Commission proposed to require interregional coordination between public utility transmission providers in neighboring transmission planning regions with respect to transmission facilities that are proposed to be located in both regions, as well as interregional transmission facilities that are not proposed but that could address transmission needs more efficiently than separate intraregional transmission facilities.[346]

ii. Comments

406. The Commission received a number of comments addressing the geographic scope of the proposed interregional coordination requirements, as well as the specific entities within the appropriate geographic scope that would be required to coordinate. Several commenters suggest that the Commission clarify how it defines regions for purposes of regional transmission planning to provide clarity as to how its proposed interregional transmission planning requirements will be implemented.[347] Transmission Dependent Utility Systems recommend that the Commission define regional boundaries if it appears that there is discrimination or inefficiencies in the planning process. Others urge the Commission not to change existing areas over which transmission planning is now coordinated among transmission planning regions.[348] For example, Integrys suggests that the Final Rule should preserve the existing mandate that PJM and the MISO constitute a single common market in the application of interregional transmission planning rules, and thus should be considered, at least for certain purposes, a single region subject to the interregional transmission planning and cost allocation rules.

407. New York Transmission Owners agree with the Commission's proposal to require that interregional transmission planning agreements between neighboring planning regions address transmission facilities that are proposed to be located in both regions. However, New York ISO states that this requirement should not preclude planning regions from considering other types of projects.

408. Several commenters either agree with the Commission's encouragement to extend interregional planning voluntarily beyond coordination between neighboring transmission planning regions so as to cover larger areas or an interconnection, or ask the Commission to require planning over such larger areas. ITC Companies state that, because some projects may involve more than two transmission planning regions, interregional planning also may need to involve more than two transmission planning regions. WECC suggests that because it already serves as a facilitator for interconnectionwide transmission planning and coordination in the Western Interconnection, it could provide a forum for facilitating multilateral transmission planning agreements. Federal Trade Commission recommends that the Commission institutionalize interconnectionwide transmission planning to incorporate relevant congestion, reliability, and environmental considerations and to reflect the geographic scope of power flows.

409. AWEA recommends that the Commission require public utility transmission providers to enter into multilateral, or even interconnectionwide, interregional transmission planning agreements. Similarly, Wind Coalition encourages the Commission to consider extending its proposed interregional transmission planning requirements beyond adjacent planning regions to provide a process

[345] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114–15.

[346] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 116.

[347] *E.g.,* Integrys; Transmission Dependent Utility Systems; and MISO Transmission Owners.

[348] *E.g.,* Integrys and National Grid.

for accessing location-constrained resources located in more distant regions. Grasslands contends that the Commission should not limit its proposed interregional coordination requirements to neighboring transmission planning regions within the same interconnection. Without interregional transmission planning between the interconnections, Grasslands claims that transmission developers will not develop transmission facilities that will efficiently link the interconnections in the future.

410. Organization of MISO States cautions that, even with implementation of the proposed interregional transmission planning requirements, it may be difficult to require any non-RTO or non-ISO public utility transmission provider to act in the best interests of a geographic footprint beyond its own. Thus, it states that efforts such as the Eastern Interconnection States Planning Council, which would view projects over a geographic region larger than the RTO footprint, may be valuable.

411. Other commenters support the Commission's intent not to mandate interconnectionwide transmission planning,[349] offering among other things that mandating interconnectionwide planning would increase the difficulty of resolving local issues by making coordinated planning among transmission planning regions more complex and risk frustrating the ARRA-funded interconnectionwide transmission planning initiatives.

412. American Transmission and MISO Transmission Owners state that with respect to planning activities in regions without an RTO or ISO, the Commission should provide guidance as to which entities would be required to coordinate with each other. Integrys states that the Commission might implement its proposed interregional transmission planning requirements in non-RTO regions by requiring transmission providers in such regions to form planning consortia that could operate within a region and/or between two or more regions. Indianapolis Power & Light suggests that the Commission clarify whether transmission providers would be required to coordinate with each individual entity or one planning region to coordinate with another planning region.

413. New York ISO states that the Commission should clarify that public utility transmission providers that are unable to reach interregional transmission planning agreements with neighboring Canadian systems will not be deemed out of compliance with the Final Rule.

414. MISO Transmission Owners state that the agreements should enable a region impacted by a proposed project located in a neighboring region to review the neighboring region's plans, and that the transmission planning regions subject to the agreement should agree on what level of impact is material, as well as how disputes between the parties will be resolved. Edison Electric Institute and Exelon likewise state that the Commission should require that interregional transmission planning agreements address transmission facilities located in a single region that could have significant adverse impacts on the reliability of neighboring regions. Moreover, Exelon states that interregional transmission planning agreements should require that if a proposed project would result in any reliability violations or increased congestion on a neighboring system, these impacts must be mitigated before the project is approved.

iii. Commission Determination

415. We require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to implement the interregional transmission coordination requirements adopted in this Final Rule. This requirement is necessary to improve coordination of neighboring transmission planning regions' activities, facilitating the identification and joint evaluation of interregional transmission solutions that could meet local and regional transmission needs more efficiently or cost-effectively than separate regional transmission solutions alone.

416. The Commission declines to expand the interregional transmission coordination requirements adopted herein to require joint evaluation of the effects of a new transmission facility proposed to be located solely in a single transmission planning region. Although this Final Rule requires each regional transmission planning process to identify the consequences of a proposed new transmission facility in another transmission planning region as we explain below in the discussion of Cost Allocation Principle 4,[350] we do not require that be done interregionally. To do so could have the effect of mandating interconnectionwide transmission planning, given that transmission facilities located within one transmission planning region often have effects on multiple neighboring systems, which could trigger a chain of multilateral evaluation processes. However, we believe that the exchange of planning data and information between neighboring transmission planning regions consistent with the interregional transmission coordination requirements of the Final Rule will assist transmission planners in understanding and managing the effects of a transmission facility located in one region upon another neighboring region. Further, although we decline to impose a joint evaluation by more than one region of a facility located solely in one transmission planning region, nothing in this Final Rule precludes public utility transmission providers from developing and proposing interregional processes for that purpose.[351]

417. While the Commission declines to require multilateral or interconnectionwide coordination in this Final Rule, we continue to encourage public utility transmission providers to explore the possibility of multilateral interregional transmission coordination among several, or even all, transmission planning regions within an interconnection, building on the processes developed through the ARRA-funded transmission planning initiatives. The Commission agrees that imposing multilateral or interconnectionwide coordination requirements at this time could frustrate the progress being made in the ARRA-funded transmission planning initiatives. To the extent that stakeholders in those planning initiatives wish to continue these activities at the conclusion of the ARRA-funded transmission planning initiatives, we encourage them to explore how existing regional transmission planning processes and interregional transmission coordination procedures implemented under Order No. 890 and this Final Rule could be enhanced to provide for such transmission planning activities.

[349] *E.g.,* Indianapolis Power & Light; Transmission Access Policy Study Group; MISO Transmission Owners; New York ISO; and Organization of MISO States.

[350] *See* discussion *infra* section IV.E.5. of this Final Rule.

[351] Moreover, the absence of such a requirement in this Final Rule does not affect any obligations public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including but not limited to any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice.

418. We decline to adopt Grasslands' recommendation that the Commission require interregional transmission coordination between transmission planning regions located in different interconnections. While we recognize that interregional transmission coordination between transmission planning regions in different interconnections could provide transmission planning benefits, such as increased power flows between interconnections, it may provide greater benefits for some pairs of neighboring transmission planning regions than for others due to geographical and operational limitations. Therefore, while we encourage public utility transmission providers to consider coordinating with neighboring transmission planning regions in different interconnections where it would be helpful, we do not find it appropriate to require such coordination in this Final Rule.

419. In response to American Transmission and MISO Transmission Owners' request for guidance regarding the entities that they are required to coordinate with in neighboring regions without an RTO or ISO, we reiterate that we require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection. Thus, interregional transmission coordination would occur between the public utility transmission providers in two neighboring transmission planning regions.

420. As discussed above in the regional transmission planning section,[352] the Commission declines to revisit how each transmission planning region defines itself, as requested by Integrys and Transmission Dependent Utility Systems. We also decline to adopt Integrys' suggestion that the Commission could implement its interregional transmission coordination requirements in non-RTO regions by requiring public utility transmission providers in such regions to form planning consortia. Public utility transmission providers are free to do so; however, we do not want to foreclose other approaches to meeting the interregional transmission coordination requirements in this Final Rule.

421. We clarify for New York ISO that a public utility transmission provider will not be deemed out of compliance with this Final Rule if it attempts to and is unable to develop interregional transmission coordination procedures with neighboring transmission systems in another country.

3. Implementation of the Interregional Transmission Coordination Requirements

a. Procedure for Joint Evaluation

i. Comments

422. Several commenters express support for the Commission's proposal to require the development of a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in neighboring transmission planning regions.[353] Some commenters seek clarification of this requirement. For example, Duke suggests that the Commission clarify whether it intends that only one joint interregional study will be performed for a proposed interregional project, regardless of the number of regions that are crossed, as multiple studies would result in an inefficient use of resources. ISO/RTO Council and PJM ask whether the Commission intends ''joint evaluation'' to mean coordination of stakeholder meetings and processes and/or the creation of a new set of planning criteria and a new planning cycle. In addition, PJM requests clarification as to whether the Commission intends ''joint evaluation'' to be conducted consistent with an interregional agreement such as the PJM/MISO Joint Operating Agreement.

423. Several commenters urge the Commission to provide flexibility in developing and implementing planning agreements.[354] They state that although the Commission proposed to require that interregional transmission planning agreements include the four elements of interregional coordination, the Commission also encouraged every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement. ISO New England urges the Commission to allow flexibility for regions to define in their interregional transmission planning agreements what it means to ''jointly evaluate'' interregional projects.

424. In setting out the details of interregional coordination, PUC of Nevada urges the Commission to consider the ongoing efforts in the Western Interconnection to address interregional coordination. WestConnect Planning Parties state that any requirement to execute an interregional transmission planning agreement should respect the various organizational structures of existing regional and interregional planning processes, as well as allow signature by all formal participants in the interregional planning process instead of requiring ''formation of a legal entity authorized to act on behalf of those participants.''

425. Other commenters offer specific suggestions as to the design and implementation of interregional coordination procedures. Minnesota PUC and Minnesota Office of Energy Security argue that, for the studies of an entire project to be meaningful and informative, all transmission planning entities studying a project should be required to coordinate their information and studies. Pioneer Transmission recommends that the Commission require planning regions to evaluate interregional projects through a single, coordinated process. It believes that if projects are studied under separate procedures by each planning region, interregional coordination would be unnecessarily delayed and more expensive than if the project was studied under a single set of procedures. However, Connecticut & Rhode Island Commissions contend that the Commission should require that proposed interregional projects be independently processed through each applicable regional planning process before they are eligible for joint evaluation through interregional coordination procedures.

426. Old Dominion similarly recommends that coordinated analysis of interregional transmission facilities be accomplished through preliminary evaluation within existing regional transmission planning processes, followed by an evaluation of the project on an interregional basis. If the identified transmission facility is determined to meet interregional needs, the relevant transmission planning regions would incorporate the project into their regional transmission planning processes and further assess its effects on regional needs. Old Dominion recommends that the Commission require this ''feedback loop'' so that local and regional transmission plans can be reconsidered once an interregional transmission plan has been developed. Similarly, New England States Committee on Electricity supports the Commission's proposed interregional coordination requirements provided that interregional projects will be identified and developed through the current approach that begins with and respects the regional transmission

[352] *See supra* section III.A.3 of this Final Rule.

[353] *E.g.,* American Transmission; New York Transmission Owners; Northeast Utilities; and Transmission Dependent Utility Systems.

[354] *E.g.,* PUC of Nevada; New York ISO; and Dayton Power and Light.

planning process and resulting regional transmission plan.

427. Several commenters suggest that the Commission should develop a *pro forma* interregional transmission planning agreement. NextEra suggests that such an agreement include the steps by which the regions and their stakeholders will identify the transmission facilities necessary to meet their needs. Otherwise, NextEra contends that the negotiation of such agreements is likely to be cumbersome. ITC Companies agrees that development of a *pro forma* interregional planning agreement would provide clarity regarding the Commission's minimum requirements and, if designed properly, could avoid replication of flaws in existing transmission planning processes that occurred in the PJM and MISO Joint Operating Agreement. In its reply comments, PJM agrees with ITC Companies that a more standardized planning process that includes a *pro forma* interregional planning agreement could improve coordination with respect to interregional facilities, and cautions that the Commission cannot simply recite regional differences as the basis for not establishing broader criteria. However, PJM contends that ITC Companies' argument regarding the Joint Operating Agreement is likely premised on the fact that their project was not selected in the RTOs' respective regional transmission plans. In its reply, Southern California Edison argues that adopting a *pro forma* agreement is not workable because planning coordination differs significantly at each RTO/ISO and among vertically integrated utilities.

428. Pennsylvania PUC suggests that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission regions negotiating bilateral coordination agreements. Pennsylvania PUC warns, however, that the joint operating agreement between PJM and MISO may require improvement in both content and operation with regard to interregional transmission planning and construction.

429. PJM requests that, before requiring greater interregional coordination, the Commission clarify whether it will continue to allow regional differences in transmission planning processes or it intends to require greater standardization among regional planning processes to achieve interregional coordination. Old Dominion agrees, recommending that the Commission provide guidance addressing the extent to which regional differences can be modified to enhance interregional transmission planning—potentially by requiring an interim compliance measure where regions report to the Commission on their progress, identify differences in regional transmission planning and/or cost allocation, and request guidance where needed. Southern Companies states on reply that, while they have no objection to the Commission encouraging additional coordination, the Commission should not attempt to mandate (directly or indirectly) uniformity or standardization. Other commenters urge flexibility to accommodate regional differences.[355]

430. Several commenters emphasize the need for more consistent data formats, modeling, planning assumptions, planning standards and protocols, and evaluation procedures and metrics (among other elements of and tools used in the transmission planning process) between transmission planning regions or for use in interregional transmission planning to ensure that the proposed reforms are effective.[356] East Texas Cooperatives cite examples of inconsistent metrics and assumptions that they contend have hindered effective interregional planning between SPP and Entergy, including the use of: (1) Different metrics to calculate available flowgate capacity at the seams; (2) different planning horizons; and (3) different types of proposed transmission upgrades in the long-term models for granting transmission service. Exelon asks the Commission to require the use of the same modeling assumptions and planning criteria, which should reflect actual expected operating conditions, when studying the impacts of a proposed interregional transmission facility on the reliability and congestion of neighboring systems. WIRES argues for the establishment of common interregional planning protocols by the Commission that can be employed by planners and stakeholders to guide development of interregional agreements on data, assumptions, and procedures that will be the foundation of genuine interregional planning processes. ITC Companies also recommends that the Commission require common assumptions and goals for long-term planning. Minnesota PUC and Minnesota Office of Energy Security recommend that project sponsors be required to provide usable data to all transmission planning entities that must study their projects.

431. Several commenters express concern that interregional planning processes could occur at different times and argue that a timeline should be established such that all planning regions consider interregional projects using the same timeline.[357] MidAmerican argues that interregional planning should be undertaken on a common time horizon, such as 20 years or longer. Organization of MISO States recommends that the Commission consider requiring the establishment of deadlines for submitting an interregional project for joint evaluation to avoid any negative impacts on each individual transmission planning region's planning process. ISO New England, however, argues against requiring interregional projects to be evaluated simultaneously by both regions or in joint sessions of both regions' stakeholders, asking instead that sequential evaluation by each region be allowed. Pioneer Transmission opposes sequential evaluation and recommends that the Commission require that interregional transmission planning agreements include specific milestones to ensure that proposed interregional projects are evaluated in a timely manner. Pioneer Transmission cautions, however, that interregional projects already before a transmission planning region should not be required to start over, which could possibly delay the overall evaluation process. MISO Transmission Owners agree that the proposed requirement should not interfere with existing transmission planning cycles.

432. American Transmission and the MISO Transmission Owners further recommend that interregional coordination procedures must allow for ''out-of-cycle'' reviews of interregional projects to address reliability issues. However, Wisconsin Electric Power Company suggests that the Commission require that adjacent planning regions align the timelines of their regional transmission planning processes to facilitate interregional coordination.

433. Several commenters support the Commission's proposed requirement that a proposed interregional transmission project must be included in each relevant regional transmission plan to be subject to the interregional cost allocation method.[358] Duke supports the proposed requirement

[355] *E.g.,* California Commissions; Dayton Power and Light; and NARUC.

[356] *E.g.,* WIRES; Wisconsin Electric Power Company; Pioneer Transmission; Organization of MISO States; Pennsylvania PUC; 26 Public Interest Organizations; East Texas Cooperatives; and ITC Companies.

[357] *E.g.,* Indianapolis Power & Light; California ISO; Organization of MISO States; and Solar Energy Industries and Large-scale Solar.

[358] *E.g.,* New York ISO; New York Transmission Owners; and Transmission Dependent Utility Systems.

subject to the acknowledgement that inclusion in a plan does not mean that a given project will be constructed. Connecticut & Rhode Island Commissions contend that a region should not be required to accept an allocation of a transmission facility's costs unless the region approved the facility in its planning process and has identified concrete benefits that would accrue to the region. Organization of MISO States asks the Commission to clarify what would happen if, after neighboring regions' joint evaluation of a proposed interregional project, the project were found to benefit one region, but not the other. New England States Committee on Electricity supports the Commission's approach to interregional coordination as long as interregional transmission projects sponsored by one region will not be imposed involuntarily on another region. However, Anbaric and PowerBridge suggest that, once selected to go ahead, an interregional transmission project should bypass the planning region's normal procedures and be assigned to an interregional team to expedite and oversee the project, to ensure timely development of the facilities.

434. First Wind suggests that a region from which renewable energy is to be exported may not experience reliability, economic, or public policy benefits as a result of an interregional transmission project and, thus, the exporting region may not include the project in its regional transmission plan. To ensure that renewable resources are able to access markets in which they can command the best price, First Wind suggests that the regional state committee representing the importing region be able to identify that an interregional transmission project is necessary to achieve public policy objectives and consequently have it included in the exporting region's regional transmission plan.

ii. Commission Determination

435. The Commission requires the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions. The establishment of a procedure by which a public utility transmission provider will identify and jointly evaluate is necessary for facilitating the identification of interregional solutions that may resolve each region's needs more efficiently or cost-effectively. As a result, the Commission and transmission customers will have greater certainty that the transmission facilities in each regional transmission plan are the more efficient and cost-effective solutions to meet the region's needs.

436. The Commission also requires the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. The submission of the interregional transmission project in each regional transmission planning process will trigger the procedure under which the public utility transmission providers, acting through their regional transmission planning process, will jointly evaluate the proposed transmission project. This joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project. Finally, for an interregional transmission facility to receive cost allocation under the interregional cost allocation method or methods developed pursuant to this Final Rule, the transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation.

437. Some commenters such as ISO/RTO Council express concern that joint evaluation of proposed interregional transmission facilities could involve the creation of a new set of planning criteria, while others such as Exelon stress the need for greater consistency in planning criteria and modeling assumptions used by neighboring regions. As a general matter, we note that joint evaluation of a proposed interregional transmission facility cannot be effective without some effort by neighboring transmission planning regions to harmonize differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project. We therefore direct, as part of compliance with the interregional transmission coordination requirements, that each public utility transmission provider, through its transmission planning region, develop procedures by which such differences can be identified and resolved for purposes of jointly evaluating the proposed interregional transmission facility. We leave to each pair of neighboring regions, however, discretion in the way this requirement is designed and implemented and do not require that any particular planning horizons or criteria be used. In response to Minnesota PUC and Minnesota Office of Energy Security, we discuss in the opportunities for discrimination against non-incumbent transmission developers section the information that a transmission developer must provide to the transmission planning region in support of its transmission project proposal.[359]

438. Some commenters argue that the Commission should establish the timeframe within which regions must jointly evaluate interregional transmission projects. The Commission declines to specify a timeline for the interregional transmission coordination procedures or a deadline by which all interregional transmission projects must be submitted. Instead, the Commission expects public utility transmission providers in neighboring transmission planning regions to cooperate and develop timelines that allow for coordination and joint evaluation of interregional transmission projects in the same general time frame as each region's consideration of the transmission project. Furthermore, we disagree with those commenters that argue that there should be sequential evaluation of transmission projects, as opposed to evaluation on the regional and interregional levels in the same general time frame. However, we clarify for ISO New England that we will not require that interregional transmission projects be evaluated simultaneously by both regions or in joint sessions of both regions' stakeholders.

439. Rather, we require that both regions conduct joint evaluation of an interregional transmission project in the same general timeframe. By same general time frame, the Commission expects public utility transmission providers to develop a timeline that provides a meaningful opportunity to review and evaluate through the interregional transmission coordination procedures information developed through the regional transmission planning process and, similarly, provides a meaningful opportunity to review and use in the regional transmission planning process information developed in the interregional transmission coordination procedures. Rather than provide further detailed guidance on this matter in this Final Rule that may unduly constrain the planning time line of each region for purposes of coordination with one or several neighboring regions, we prefer in the first instance to permit regions to develop appropriate timing arrangements with neighbors, which we will review on compliance.

440. American Transmission and the MISO Transmission Owners

[359] *See* discussion *supra* section III.B.3.d.ii.

recommend that interregional transmission coordination procedures must allow for ''out-of-cycle'' reviews of interregional transmission projects to address reliability issues. The Commission believes that a requirement for ongoing constant reviews without regard to a defined planning cycle would be too burdensome. This Final Rule does not require such an ''out-of-cycle'' review, nor does it prohibit a region or a pair of regions from doing so, for example if necessary to address a pressing reliability issue. Additionally, while the creation of a new planning cycle may be unnecessary, the Commission is requiring that coordination and joint evaluation must be conducted in the same general time frame as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project.

441. Furthermore, we decline to adopt suggestions to require adjacent transmission planning regions to align the timelines of their regional transmission planning processes. The Commission is providing flexibility, subject to certain requirements, in the design and implementation of procedures to govern the joint evaluation of interregional transmission facilities by neighboring transmission planning regions. To the extent public utility transmission providers in neighboring transmission planning regions identify changes to their regional transmission planning processes that are necessitated by implementation of interregional transmission coordination procedures, those transmission providers should implement those changes as part of their compliance filings submitted in response to this Final Rule.

442. In response to New England States Committee on Electricity's comment that interregional transmission coordination should begin with and respect the regional transmission planning process and resulting regional transmission plan, we note that we require in this Final Rule that the developer of a transmission project that would be located in more than one transmission planning region first must propose its transmission project in the regional transmission planning process of each of those transmission planning regions. We expect each transmission planning region's review of that transmission project to be informed by and closely coordinated with the interregional transmission coordination procedures. Furthermore, the Commission did not propose in the Proposed Rule, and will not require in this Final Rule, that interregional transmission coordination procedures provide for the costs of an interregional transmission project sponsored by one transmission planning region to be involuntarily imposed on another transmission planning region.

443. Finally, the Commission agrees with Duke that having an interregional transmission facility in a regional transmission plan does not mean that it will be constructed. As in Order No. 890, the goal of this Final Rule is to establish procedures by which neighboring transmission planning regions will coordinate to jointly evaluate proposed transmission facilities, not to dictate which investment must be made or transmission projects must be built.[360] In response to Connecticut & Rhode Island Commissions, the Commission clarifies that public utility transmission providers in a transmission planning region will not be required to accept allocation of the costs of an interregional transmission project unless the region has selected such transmission facility in the regional transmission plan for purposes of cost allocation. That is, based on the information gained during the joint evaluation of an interregional transmission project, each transmission planning region will determine, for itself, whether to select those transmission facilities within its footprint in the regional transmission plan for purposes of cost allocation. Whether a transmission planning region would decide to select an interregional transmission facility in its regional transmission plan likely would be driven by the relative costs and benefits of the transmission project to that region. The Commission believes this effectively provides the ''feedback loop'' sought by Old Dominion.

444. The Commission declines to adopt the suggestion by Anbaric and PowerBridge that an interregional transmission project resulting from the interregional transmission coordination procedures be allowed to bypass the relevant regions' transmission planning processes and be automatically assigned to an interregional team. However, we do not preclude the public utility transmission providers in a pair of transmission planning regions from creating a separate process for developing interregional transmission facilities that have been in each relevant transmission planning region's plan. Instead, we provide transmission planning regions with flexibility to determine how to address an interregional transmission project. We reiterate that, to be eligible for interregional cost allocation, the interregional transmission facility must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission facility is proposed to be located.

445. Beyond the clarifications provided above, we decline to address the remaining requests to further delineate how neighboring transmission regions must jointly evaluate proposed interregional transmission facilities because such action could inadvertently impose requirements that are not appropriate for particular regions. Given the flexibility we have provided to public utility transmission providers in implementing the interregional transmission coordination requirements, the Commission determines it is unnecessary to adopt interim compliance requirements or other processes such as those suggested by Old Dominion.

446. We decline to adopt First Wind's suggestion that a transmission planning region should be required to include a transmission project intended to export renewable energy resources in its regional transmission plan if the regional state committee representing the importing region identifies the transmission project as necessary to achieve a public policy objective. As discussed above, whether an interregional transmission facility is to be selected in the regional transmission plan for purposes of cost allocation is a decision left to each transmission planning region. However, we will not preclude public utility transmission providers in neighboring transmission planning regions from voluntarily developing procedures such as those proposed by First Wind should they agree to do so as part of their interregional transmission coordination efforts.

447. In response to commenters' recommendations that the Commission provide for regional flexibility in developing and implementing interregional transmission coordination, we reiterate the Commission's encouragement in the Proposed Rule that interregional transmission coordination procedures be tailored to best fit the needs of the public utility transmission providers in the regions involved while also meeting certain minimum requirements.[361]

448. Furthermore, as urged by PUC of Nevada, we are cognizant of existing

[360] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438.

[361] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 117.

interregional transmission coordination efforts and, by providing regional flexibility, intend to accommodate their various organizational structures, as suggested by WestConnect Planning Parties. Consistent with this approach, any public utility transmission provider that believes its existing interregional transmission coordination procedures, including those found in any interregional transmission planning agreement, already comply with the requirements of this Final Rule may indicate in its compliance filing how its existing procedures meet each requirement. If the existing procedures do not meet all of the requirements, the public utility transmission provider may propose revisions to its existing interregional transmission coordination procedures so that the procedures comply with this Final Rule.

449. Because we want to allow for regional flexibility, we decline to adopt commenters' suggestions that the Commission develop *pro forma* interregional transmission coordination procedures or impose additional requirements as to what interregional transmission coordination should entail. As noted by Southern California Edison, planning coordination differs significantly at each RTO and ISO and among vertically integrated utilities, and we thus determine that *pro forma* interregional transmission coordination procedures are not appropriate at this time because it may not accommodate the differences among existing transmission planning regions. Moreover, the requirements that we adopt as interregional transmission coordination requirements in this Final Rule should be adequate guidance for public utility transmission providers.

450. We also note the Pennsylvania PUC's suggestion that the joint operating agreement between PJM and MISO, which includes a section on coordinated regional transmission planning requirements, could serve as a model for neighboring transmission planning regions negotiating bilateral coordination agreements. While we generally agree that various existing transmission planning agreements between regions may serve as models, we note that existing agreements reflect the needs of the regions that negotiated them. Thus, the Commission declines to require public utility transmission providers to adopt or model their coordination procedures on any particular agreement to coordinate transmission planning between two regions.

b. Data Exchange

i. Comments

451. American Transmission supports the Proposed Rule's requirement that interregional transmission planning agreements include an agreement to exchange planning data and information at least annually. American Transmission states that this requirement would help ensure that neighboring regions are aware of planning considerations as well as any transmission issues in neighboring regions. It also recommends that the Commission establish a time frame for a neighboring transmission planning region to respond to a transmission provider's request for planning information and data. SPP recommends that the Commission require interregional transmission planning agreements to include the specific procedures for sharing such information rather than only an agreement to do so.

452. Several commenters state that this exchange should be required to occur more often than annually.[362] NextEra states that the Commission should require the exchange of planning data and information at least as frequently as warranted by any material developments that either affect any neighboring region or interregional facility or may influence any interregional transmission plan. Organization of MISO States recommends that the Commission modify this element to require exchange of planning data and information at least semi-annually because transmission planning analysis can change over the course of a planning cycle due in part to changing modeling results and stakeholder input. Minnesota PUC and Minnesota Office of Energy Security recommend that the Commission require planning data and information exchanges between transmission planning regions to occur semi-annually to account for those project proposals that are requested to be reviewed out-of-cycle.

453. Transmission Dependent Utility Systems and Pennsylvania PUC express concern that this proposed element does not consider differences in the planning processes of each region. For example, Transmission Dependent Utility Systems state that the proposed planning data and information exchange requirement may be inadequate to address interregional transmission infrastructure concerns, and that transmission providers and stakeholders should be permitted to determine the type and frequency of meetings and planning information exchanges. Likewise, Pennsylvania PUC states that this requirement should accommodate different transmission planning regions' planning cycles.

ii. Commission Determination

454. The Commission requires each public utility transmission provider, through its regional transmission planning process, to adopt interregional transmission coordination procedures that provide for the exchange of planning data and information at least annually. The sharing of data at least once a year will ensure that neighboring transmission planning regions are aware of each others' transmission plans and the assumptions and analysis that support such plans. In response to arguments that the Commission should require neighboring transmission planning regions to exchange data more frequently, we note that this Final Rule provides that this information must be exchanged *at least* annually, thereby allowing each public utility transmission provider through its transmission planning region, the flexibility to decide to exchange information more frequently. If a pair of transmission planning regions anticipates that more frequent exchanges of planning data and information would improve interregional transmission coordination, then we encourage them to provide for such exchanges in their interregional transmission coordination procedures.

455. We agree with SPP that interregional transmission coordination procedures must include the specific obligations for sharing planning data and information rather than only an agreement to do so. A clear description of the procedures that will be used to exchange planning data and information will help the Commission, transmission customers, and other stakeholders to better determine if each public utility transmission provider is fulfilling its obligations consistent with this Final Rule. However, we will not dictate the specific procedures or the level of detail for the procedures pursuant to which planning data and information must be exchanged. Consistent with the comments of Transmission Dependent Utility Systems and Pennsylvania PUC, we allow each public utility transmission provider, through its transmission planning region, to develop procedures to exchange planning data and information, which we anticipate will reflect the type and frequency of meetings that are appropriate for each pair of regions and

[362] *E.g.,* Minnesota PUC and Minnesota Office of Energy Security; NextEra; and Organization of MISO States.

will accommodate each pair of region's planning cycles.

c. Transparency

i. Comments

456. Pennsylvania PUC supports the proposed requirement that interregional transmission planning agreements include a commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated planning process. Duke requests the Commission clarify that information relating to the interregional transmission planning process can be maintained on an existing transmission provider's Web site or regional transmission planning Web site.

457. In addition, MISO Transmission Owners suggest that all transmission providers offering transmission service or interconnection service under a tariff (including a non-jurisdictional tariff) should be required to make publicly available their business practice manuals or other documentation specifically detailing the assumptions and criteria used in comparably evaluating all proposed transmission and generation projects, including the identification and treatment of third-party impacts.

ii. Commission Determination

458. The Commission requires public utility transmission providers, either individually or through their transmission planning region, to maintain a Web site or e-mail list for the communication of information related to interregional transmission coordination procedures. The Commission clarifies that information related to interregional transmission coordination may be maintained on an existing public utility transmission provider's Web site or a regional transmission planning Web site. However, the information should be posted in such a way that stakeholders are able to distinguish between information related to interregional transmission coordination and information related to regional transmission planning.

d. Stakeholder Participation

i. Commission Proposal

459. In the Proposed Rule, the Commission did not specifically address the issue of stakeholder participation with regard to the coordination of transmission planning activities undertaken by neighboring transmission regions.

ii. Comments

460. Some commenters discuss the need for utilities and stakeholders to participate in the process of developing interregional planning agreements. Transmission Access Policy Study Group states that interregional transmission planning agreements must be inclusive, open, and collaborative. Both Transmission Access Policy Study Group and East Texas Cooperatives state that transmission dependent utilities should have the opportunity to participate in their development and implementation. Transmission Access Policy Study Group states that, without such a requirement, the Commission would not be fulfilling its responsibility under FPA section 217(b)(4) to facilitate planning to meet the needs of all load-serving entities. Wisconsin Electric Power Company requests that the Commission explicitly ensure that stakeholders have the opportunity to participate in the development of these agreements.

461. Some commenters contend that the interregional transmission planning requirements described in the Proposed Rule could be significantly improved with respect to stakeholder participation. New York PSC states that the Commission should articulate that meaningful participation in the planning process is necessary, including the opportunity to provide input concerning how studies are conducted and solutions are identified. Transmission Dependent Utility Systems contend that it is just as important for transmission customers to be able to participate in interregional transmission planning as it is for them to be able to participate in regional transmission planning.

462. Integrys states that because stakeholder involvement and input is necessary to ensure proper planning and evaluation of projects, the Commission should adopt a stakeholder participation requirement in any Final Rule. Xcel states that the interregional coordination necessary to support the development of larger-scale, interregional transmission projects (particularly those that are needed to integrate renewable energy resources) must engage stakeholders, and especially state regulatory agencies, in the development of processes that address the specific needs and requirements of the participating regions. Without the involvement of state agencies, which ultimately decide which transmission facility will be built, Xcel contends that interregional transmission planning processes will not result in the construction of needed transmission.

463. Energy Future Coalition states that interregional transmission planning must be both participatory and analytically robust by engaging all interested parties, including utilities, states, renewable generation developers, environmental interests, and consumer interests.

464. Some commenters express concern that, even if the proposed interregional transmission planning requirements provide for stakeholder participation, such participation can require significant resources from stakeholders. NARUC and Massachusetts Departments claim that limited human resources and budgets make it difficult for state commissions and other stakeholders to participate in additional transmission planning processes. Massachusetts Departments suggest that any Final Rule should take these challenges into account and consider mechanisms to address them. Similarly, California Commissions comment that states must have access to adequate resources to support state involvement in interregional coordination processes and that the Commission could consider requiring stakeholder support beyond that provided through the ARRA-funded interconnectionwide transmission planning initiatives.

iii. Commission Determination

465. We agree with those commenters that argue stakeholder participation is an important component in interregional transmission coordination to ensure the goals of improving coordination between neighboring transmission planning regions and identifying interregional transmission facilities that can address transmission needs more efficiently or cost-effectively than separate intraregional transmission facilities. However, this Final Rule does not require the interregional transmission coordination procedure to meet the requirements of the planning principles required for local planning (under Order No. 890) and regional planning (under this Final Rule).[363] Because we require in this Final Rule that an interregional transmission facility must be selected in each relevant regional transmission plan for purposes of cost allocation to be eligible for interregional cost allocation, stakeholders will have the opportunity to participate fully in the consideration of interregional transmission facilities during the regional transmission

[363] Of course, nothing precludes public utility transmission providers in neighboring transmission planning regions from choosing to meet those requirements.

planning process.[364] Furthermore, we believe that stakeholder participation in the various regional transmission planning processes will enhance the effectiveness of interregional transmission coordination. To facilitate stakeholder involvement, this Final Rule requires the public utility transmission providers to make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[365]

466. We also agree with commenters that discuss the importance of transmission customer and stakeholder participation in the development of the interregional transmission coordination procedures necessary to comply with the requirements in this Final Rule. Therefore, we require that each public utility transmission provider give stakeholders the opportunity to provide input into the development of its interregional transmission coordination procedures and the commonly agreed-to language to be included in its OATT.

467. The Commission appreciates the concerns of NARUC and others regarding the effect budgetary limitations could have on effective stakeholder participation in interregional transmission coordination activities. As discussed above in the regional transmission planning section[366] and consistent with Order No. 890, to the extent that public utility transmission providers choose to include a funding mechanism to facilitate the participation of state consumer advocates or other stakeholders in the regional transmission planning process, nothing in this Final Rule precludes them from doing so.

e. Tariff Provisions and Agreements for Interregional Transmission Coordination

i. Commission Proposal

468. In the Proposed Rule, the Commission proposed to require that coordination between neighboring transmission planning regions be reflected in an interregional transmission planning agreement to be filed with the Commission.[367]

ii. Comments

469. Several commenters express support for the Commission's proposal to require neighboring regions to enter into interregional transmission planning agreements.[368] They also emphasize, however, that planning regions should be able to structure planning agreements so that each region is a full, equal partner and no region can force projects or costs onto other regions in a manner that is inconsistent with the agreement. Edison Electric Institute further emphasizes that these planning agreements cannot replace strong interregional coordination to address interregional impacts.

470. Other commenters argue that the Commission should accept the submission of existing interregional agreements, with necessary modifications, to comply with the Final Rule.[369] American Transmission and MISO Transmission Owners state that when reviewing existing interregional agreements to determine their compliance with the Final Rule, if the Commission determines that modifications to these agreements are necessary, the public utility transmission providers and their stakeholders should be given the opportunity to address and submit revisions.

471. Some commenters suggest that interregional coordination procedures should be incorporated into public utility transmission providers' OATTs. Ad Hoc Coalition of Southeastern Utilities suggests that as an alternative to the interregional agreement, the Commission should consider adopting an additional planning principle that permits public utility transmission providers to explain how they address the types of matters that the Proposed Rule would require to be included in such interregional agreements. ColumbiaGrid further contends that transmission providers in the Western Interconnection should be required to include in their OATTs only the regional planning group and WECC processes and information regarding their existing relationship, and that they should not be required to divert resources to developing formal agreements to be filed with the Commission. Bonneville Power suggests that the Commission require transmission providers to include coordination requirements as part of the transmission planning processes outlined in their OATTs, but without specific details about how individual projects would be planned and developed. It states that this would allow transmission providers to enter into voluntary agreements and to focus on developing higher priority projects. Transmission Dependent Utility Systems state that each public utility transmission provider's interregional transmission planning process should be included in the OATT, subject to effective Commission and stakeholder scrutiny on an ongoing basis.

472. California ISO also contends the proposed requirements are problematic for the ISO in that it would not be able to develop an interregional transmission planning agreement applicable to all of its neighboring balancing authority areas because many of its neighboring balancing authorities have different legal charters and are subject to different laws, regulations, and requirements.

473. Several commenters raised concerns about the proposed interregional transmission planning agreements with respect to non-jurisdictional transmission providers. Western Area Power Administration requests that the Final Rule acknowledge that interregional transmission planning-related agreements would need to account for the status and statutory requirements of non-public utility transmission providers before they may be executed. Large Public Power Council states its members will commit to voluntarily participate in interregional transmission planning processes, but that its members have limited authority to enter into agreements that include, among other things, an obligation to pay construction costs or a requirement to defer to regional or interregional planning authorities. Omaha Public Power District states that it plans to participate voluntarily in an interregional transmission planning process, but notes that its agreements to do so would not be subject to the Commission's jurisdiction or enforcement. Nebraska Public Power District expresses the same concerns regarding the lack of clarity in the commitments that it would be required to make as a result of the proposed interregional transmission planning agreements. Nebraska Public Power District also commits to participate in interregional transmission planning processes; however, it contends that it cannot make such commitment outside of its current RTO membership and the related protection against violating state law and that its authority to enter into binding agreements is limited consistent with state sovereignty.[370]

[364] *See* discussion *supra* P 0.

[365] This information must be made available subject to appropriate confidentiality protections and CEII requirements.

[366] *See* discussion *supra* section III.A.3.

[367] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 114.

[368] *E.g.,* National Grid; New York Transmission Owners; and Edison Electric Institute.

[369] *E.g.,* FirstEnergy Service Company; American Transmission; and MISO Transmission Owners.

[370] Comments addressing specific statutory provisions that may limit non-jurisdictional

Continued

474. Several commenters argue that the Commission should require non-jurisdictional entities to comply with the proposed interregional transmission planning requirements. Westar states that power flows on a non-jurisdictional entity's system can affect facilities in a jurisdictional entity's system, and vice-versa. Similarly, MISO Transmission Owners state that requiring non-jurisdictional entities to participate would ensure effective interregional transmission planning and coordination and address seams issues. NextEra states that to facilitate broad-based participation by all relevant entities, the Commission should invoke its authority under FPA section 211A to require unregulated transmitting utilities to participate in the interregional transmission planning process.

iii. Commission Determination

475. In light of the comments received, the Commission declines to require that coordination between the public utility transmission providers in pairs of neighboring transmission planning regions be reflected in a formal interregional transmission planning agreement filed with the Commission, as was proposed in the Proposed Rule. Instead, as recommended in part by Ad Hoc Coalition of Southeastern Utilities, ColumbiaGrid, Bonneville Power, and Transmission Dependent Utility Systems, we require that the public utility transmission providers in each pair of neighboring transmission planning regions, working through their regional transmission planning processes, must develop the same language to be included in each public utility transmission provider's OATT that describes the interregional transmission coordination procedures for that particular pair of regions.[371] Alternatively, if the public utility transmission providers so choose, these procedures may be reflected in an interregional transmission coordination agreement filed on compliance for approval by the Commission.[372]

476. We find that implementing the interregional transmission coordination requirements in this Final Rule through their incorporation in each public utility transmission provider's OATT, instead of requiring an interregional transmission planning agreement, will fulfill our objective to improve interregional transmission coordination and provide adequate transparency with regard to the obligations imposed on public utility transmission providers. Further, commenters persuade us that this approach would facilitate the participation of non-public utility transmission providers in an interregional transmission coordination efforts.

477. In response to commenters' arguments that the Commission should accept the submission of existing interregional agreements on compliance, we agree provided the compliance filing explains how the existing agreement satisfies the requirements of this Final Rule. The Commission will address the adequacy of such an existing agreement on compliance.

478. We decline to adopt Bonneville Power's recommendation that these procedures omit specific details about how individual transmission projects would be planned and developed, because we require each set of interregional transmission coordination procedures to include a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions.

479. We do not find convincing California ISO's argument that it will be problematic for it to develop interregional transmission coordination procedures with all of its neighboring balancing authority areas due to the differences among them. Just as reliable transmission operation of interconnected transmission systems requires coordination among neighboring utilities and regions—some of which is required by mandatory reliability standards, transmission planning of interconnected transmission systems requires some degree of coordination among neighboring utilities and regions. We conclude that this Final Rule provides for sufficient regional flexibility to allow the California ISO to develop in cooperation with its neighboring balancing authority areas interregional transmission coordination procedures that accommodate their differences.

480. We agree with commenters that interregional transmission coordination should be structured in such a way that no public utility transmission provider in a transmission planning region should be permitted to force transmission projects or costs onto another region contrary to the agreed upon interregional transmission coordination procedures incorporated into the relevant public utility transmission providers' OATTs pursuant to this Final Rule.

481. Because we are implementing the interregional transmission coordination requirements adopted in this Final Rule through incorporation of the same language into each public utility transmission provider's OATT rather than through formal agreements, we find comments presenting concerns that non-public utility transmission providers are unable to be party to interregional transmission planning agreements to be moot. Furthermore, we do not believe that it is necessary to address here those commenters that ask us to require non-public utility transmission providers to participate in interregional transmission coordination efforts. We believe such concerns are premature, as we are encouraged by the non-public utility transmission providers who expressed their intent to participate in interregional transmission coordination efforts in their comments in response to the Proposed Rule. Additional discussion of non-public utility transmission provider participation in the reforms adopted in this Final Rule, including the interregional transmission coordination requirements, is in the reciprocity section below.[373]

IV. Proposed Reforms: Cost Allocation

482. The Commission requires, as part of this Final Rule, that each public utility transmission provider have in its OATT a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan (''regional cost allocation''); and that each public utility transmission provider within a transmission planning region develop a method or set of methods for allocating the costs of new interregional transmission facilities that two (or more) neighboring transmission planning regions determine resolve the individual needs of each region more efficiently

participation in this regard are addressed in the discussion of the Commission's legal authority to undertake reforms regarding regional transmission planning. *See* discussion *infra* section III.A.2 of this Final Rule.

[371] Consistent with the approach taken in Order Nos. 890 and 890–A, public utility transmission providers may use Web-posted business practice manuals to describe planning-related processes. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1653; Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 990.

[372] However, even if a public utility transmission provider voluntarily enters into such an agreement, its OATT must still provide enough description for stakeholders to follow how interregional transmission coordination will be conducted, with links included to the actual agreement where the details can be found. *See United States Dep't of Energy—Bonneville Power Admin.*, 124 FERC ¶ 61,054, at P 65 (2008) (requiring Avista, Puget and Bonneville Power ''to provid[e] additional detail in their Attachment Ks on the WECC's [Transmission Expansion Planning Policy Committee's] process or providing direct links (*i.e.*, URLs) to the appropriate documents on the WECC Web site where the processes to coordinate information and planning efforts [between several regional planning groups] are discussed'').

[373] *See* discussion *infra* section V.B.

and cost-effectively (''interregional cost allocation''). The OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. Each of the regional cost allocation and interregional cost allocation methods must adhere to the respective general cost allocation principles as set forth below.[374] Subject to these general cost allocation principles, public utility transmission providers in consultation with stakeholders have the opportunity to develop the appropriate cost allocation methods for their new regional and interregional transmission facilities. In the event that no agreement among public utility transmission providers in a region or pair of regions can be reached, the Commission will use the record in the relevant compliance filing proceeding(s) as a basis to develop a cost allocation method or methods that meets the Commission's requirements.

483. The requirements established below are designed to work in tandem with the transmission planning requirements established above to identify more appropriately the benefits and the beneficiaries of new transmission facilities so that transmission developers, planners and stakeholders can take into account in planning who would bear the costs of transmission facilities, if constructed.

A. Need for Reform Concerning Cost Allocation

1. Commission Proposal

484. In the Proposed Rule, the Commission noted that its responsibility under sections 205 and 206 of the FPA to ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential is not new, nor is the Commission's recognition of the cost causation principle. However, the Commission explained that the circumstances in which it must fulfill its statutory responsibilities change with developments in the industry, such as changes with respect to the demands placed on the grid. For example, the expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standards, has contributed to the rapid growth of renewable energy resources that are frequently remote from load centers.

485. The Commission stated that challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. The Commission noted that constructing new transmission facilities requires a significant amount of capital and, therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. The Commission explained, however, that there are few rate structures in place today that provide both for analysis of the beneficiaries of a transmission facility that is proposed to be located within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region, and for corresponding allocation and recovery of the facility's costs. The Commission stated that lack of such rate structures creates significant risk for transmission developers that they will have no identified group of customers from which to recover the cost of their investment. With regard to cost allocation within RTO or ISO regions, the Commission noted that cost allocation issues are often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair, particularly for RTOs and ISOs that encompass several states.

486. The Commission further noted that the risk of the free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. The Commission explained that, on one hand, a cost allocation method that relies exclusively on a participant funding approach,[375] without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs would be allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose selection of the facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the facility's construction.

487. In light of these challenges and recent developments affecting the industry, the Commission stated concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities and, thus, may result in rates that are not just and reasonable or are unduly discriminatory or preferential.[376] The Commission proposed the cost allocation requirements discussed in further detail below to address this concern.

2. Comments on Need for Reform

488. A number of commenters generally support the cost allocation requirements proposed by the Commission.[377] For example, ITC Companies state that the Commission has correctly concluded that reform with respect to transmission cost allocation methods is necessary. AWEA argues that issues related to cost allocation impede transmission development required to address increased demand, meet national energy and environmental goals, and create an intelligent, secure, and reliable transmission network. Clean Line argues that implementation of a cost allocation method is critical to the development of new infrastructure. Multiparty Commenters argue that a fair allocation of the costs of new transmission can be facilitated by acknowledging that the cost of transmission is a small portion of the delivered cost of electricity, generally ten percent or less, whereas the costs of a single project may be significant for the builders of that project. Solar Energy Industries urge the Commission to use its authority to alleviate impediments to building new transmission lines for renewable energy and other system needs to promote a robust competitive market that will benefit consumers and the environment.

[374] For purposes of this Final Rule, a regional transmission facility is a transmission facility located entirely in one region. The Proposed Rule sometimes called such a facility a regional facility and sometimes an intraregional facility. An interregional transmission facility is one that is located in two or more transmission planning regions. A transmission facility that is located solely in one transmission planning region is not an interregional transmission facility.

[375] Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. The Proposed Rule cited several examples of regions relying principally or exclusively on the participant funding approach to cost allocation. Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128.

[376] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 148–54.

[377] *E.g.,* Transmission Access Policy Study Group; AWEA; Northeast Utilities; ITC Companies; Energy Future Coalition Group; MidAmerican; MISO; NextEra; E.ON Climate Renewables North America; Exelon; Iberdrola Renewables; WIRES; Western Grid Group; and Pennsylvania PUC.

489. Many commenters also support aligning transmission planning and cost allocation more closely.[378] Transmission Dependent Utility Systems state that it is virtually impossible to separate transmission planning from transmission cost allocation. Exelon argues that fair, efficient, and legal cost allocation should follow the manner in which its system is planned. Integrys agrees with linking cost allocation rules with transmission planning, but cautions that the transmission planning process is not a substitute for the cost allocation process.

490. A number of commenters supporting closer alignment between planning and cost allocation state that existing ISO and RTO transmission planning and cost allocation processes already may satisfy the proposal to align transmission planning and cost allocation more closely.[379] AEP and SPP believe that their existing transmission planning and cost allocation processes satisfy many of the Commission's proposed requirements. Similarly, MISO Transmission Owners state that cost allocation in MISO is already closely tied to the transmission planning process. Organization of MISO States points to MISO filings that address cost allocation issues.

491. WIRES asks the Commission to ensure that the planning process not be unduly influenced by those that seek to redirect potential cost allocation liability. Illinois Commerce Commission believes it is unduly discriminatory for a state to be required to bear costs for transmission expansion projects under a cost sharing arrangement but have no decisional authority for projects outside their state. Where a regional state committee exists, Illinois Commerce Commission recommends that a process be carved out by which the regional state committee's board of directors has the opportunity to review and decide on the reasonableness of each of the RTO's proposed transmission expansion projects for which regional cost allocation would apply.

492. A number of commenters express concern with the Commission's proposal to impose generic regional and interregional cost allocation requirements.[380] Some commenters argue specifically that there is no need for the Commission's proposed cost allocation reforms.[381] For example, Northern Tier Transmission Group argues that the Proposed Rule does not present a factual basis for expanding the scope of the cost allocation requirement to every project contained in a regional transmission plan. It requests that the Commission confirm that the Proposed Rule is not intended to apply to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures. If the Proposed Rule is intended to apply to all new transmission projects in a region's transmission plan, Northern Tier Transmission Group urges that the Proposed Rule be rejected. It also is concerned that shifting the burden of cost allocation for every project onto the regional transmission planning process will create an unnecessary burden on a region's collective transmission providers. Westar states that the transmission planning selection process is critical to ensure that only transmission projects that meet the various regional requirements are constructed and their costs recovered as part of tariff rates.

493. North Carolina Agencies contend that the Commission has not established that current cost allocation methods are unjust and unreasonable. Nebraska Public Power District argues that the Proposed Rule does not contain any record evidence demonstrating the need for generic rate reform and states that transmission investment has substantially increased in recent years. Salt River Project argues that the primary barriers to renewable resource development are delays and denial of siting and other permits, not transmission funding. California Municipal Utilities suggest that fewer remote resources are needed because more local renewable resources are being developed and, therefore, the need for cost allocation reforms must be re-examined. Indianapolis Power and Light believes that existing tariff requirements and ongoing proceedings will achieve the Commission's stated objective without the uncertainty of a parallel rulemaking process.

494. MEAG Power responds to Multiparty Commenters' assertion regarding the cost of transmission expansion by arguing that investments of the size actually needed to build out the transmission system, if allocated to load, would raise its native load customers' transmission costs dramatically. Sacramento Municipal Utility District states that, even if Multiparty Commenters' assertion were true, it is irrelevant to the establishment of a just and reasonable transmission rate whether it comprises a small or large portion of the cost of delivered power.[382] Large Public Power Council raises arguments similar to those raised by both MEAG Power and Sacramento Municipal Utility District.

3. Commission Determination

495. The Commission concludes that it is necessary and appropriate to adopt the cost allocation requirements described in further detail below for public utility transmission providers. The Commission finds that, without these minimum requirements in place, cost allocation methods used by public utility transmission providers may fail to account for the benefits associated with new transmission facilities and, thus, result in rates that are not just and reasonable or are unduly discriminatory or preferential.

496. In Order No. 890, the Commission found that there is a close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan.[383] The Commission explained that knowing how the costs of transmission facilities would be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.[384] In light of that relationship, the Commission directed public utility transmission providers to identify the cost allocation method or methods that would apply to transmission facilities that do not fit under previously existing rate structures.[385] After several rounds of compliance filings, the Commission accepted various public utility transmission providers' proposals as in compliance with Order No. 890. Particularly in transmission planning regions outside of the RTO and ISO

[378] *E.g.,* Atlantic Grid; ITC Companies; Sunflower and Mid-Kansas; MISO; Pennsylvania PUC; PHI Companies; Colorado Independent Energy Association; Energy Future Coalition Group; PSC of Wisconsin; CapX2020; and Wind Coalition.

[379] *E.g.,* SPP; AEP; MISO Transmission Owners; Organization of MISO States; California PUC; and Pacific Gas & Electric.

[380] *E.g.,* Arizona Public Service Company; Bonneville Power; California Transmission Planning Group; Tucson Electric; Western Area Power Administration; California Commissions; California ISO; Eastern Massachusetts Consumer-Owned System; New York PSC; Coalition for Fair Transmission Policy; Connecticut & Rhode Island Commissions; Large Public Power Council; National Grid; and Southern California Edison.

[381] *E.g.,* Ad Hoc Coalition; Southern Companies; Salt River Project; and Nebraska Public Power District.

[382] Sacramento Municipal Utility District (citing *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1508 (DC Cir. 1984)).

[383] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

[384] *Id.*

[385] *Id.* P 558.

footprints, several of the cost allocation methods that the Commission accepted relied exclusively on a participant funding approach to cost allocation.[386] The Commission did not address cost allocation for interregional transmission facilities in Order No. 890.

497. We conclude that, in light of changes within the industry and the implementation of other reforms in this Final Rule, the existing requirements of Order No. 890 are no longer adequate to ensure rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. While the existing cost allocation methods may have sufficed in the past, as we note above, the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on the transmission grid. The comments in this proceeding make clear that the pace of change has accelerated in recent years, such as the expansion of regional power markets, which has led to a growing need for transmission facilities that cross several utility, RTO, ISO or other regions. The industry's continuing transition also has enabled greater utilization of resources (*e.g.,* reserve sharing) resulting in, among other effects, broader diffusion of the benefits associated with transmission facilities. Additionally, the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus a growing need for transmission facilities to access remote resources, often traversing several utility and/or ISO/RTO regions.

498. The challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. Within RTO or ISO regions, particularly those that encompass several states, the allocation of transmission costs is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived by all stakeholders as reflecting a fair distribution of benefits. In other regions, few rate structures are currently in place that reflect an analysis of the beneficiaries of a transmission facility and for the corresponding cost allocation of the transmission facility's cost. Similarly, there are few rate structures in place today that provide for the allocation of costs of interregional transmission facilities.

499. We agree with many commenters that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process. Under the regional transmission planning and interregional transmission coordination requirements adopted in this Final Rule,[387] public utility transmission providers, in consultation with stakeholders, will identify, evaluate, and determine the set of transmission facilities that will meet the combined needs of the region or neighboring pairs of regions, respectively. This necessarily includes a determination by the region that the benefits associated with that set of transmission facilities outweigh the costs. Failing to address the allocation of costs for these transmission facilities in a way that aligns with the evaluation of benefits through the transmission planning process could lead to needed transmission facilities not being built, adversely impacting ratepayers.

500. In general and as discussed elsewhere in this Final Rule, the Commission requires a public utility transmission provider to participate in a regional transmission planning process and to coordinate transmission planning with public utility transmission providers in neighboring transmission planning regions in a manner that aligns transmission planning and cost allocation processes. Additionally, the OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region. As some commenters point out, transmission facilities that are in a transmission plan to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, address economic considerations, or enable compliance with Public Policy Requirements. Because such purposes involve the identification of expected beneficiaries, either explicitly or implicitly, establishing a closer link between transmission planning and cost allocation will ensure that rates for Commission-jurisdictional service appropriately account for benefits associated with new transmission facilities.

501. We recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. We believe that a transparent transmission planning process is the appropriate forum to address these issues. By linking transmission planning and cost allocation through the transmission planning process, we seek to increase the likelihood that transmission facilities in regional transmission plans are actually constructed.

502. Turning to specific comments on this topic, we are not persuaded to adopt Illinois Commerce Commission's proposal for separate review and decision by a committee of state regulators on the reasonableness of proposed transmission expansion projects for which regional cost allocation would apply. As explained above,[388] this Final Rule builds on Order No. 890's requirement that a public utility transmission provider have open and transparent transmission planning processes in which we encourage states or state committees to be involved. Additionally, as required by this Final Rule, through the transmission planning process, the public utility transmission providers and other parties, including state regulators, will have opportunities to participate in the identification of transmission needs. We decline, however, to mandate veto rights for state committees, but do not preclude public utility transmission providers from proposing such mechanisms on compliance if they choose to do so.[389]

503. In response to Northern Tier Transmission Group's concern that applying the new cost allocation requirements to existing transmission projects covered by existing tariff-based and contract-based cost allocation procedures will shift costs and create unnecessary burdens, we clarify that the cost allocation requirements of this Final Rule apply only to new transmission facilities [390] selected in regional transmission plans for purposes of cost allocation.

[386] *See, e.g., El Paso Electric Co.,* 124 FERC ¶ 61,051 (2008); *Xcel Energy Services, Inc.—Public Service Co. of Colorado,* 124 FERC ¶ 61,052 (2008); *South Carolina Electric & Gas Co.,* 127 FERC ¶ 61,275 (2009). *Entergy Services, Inc.,* 127 FERC ¶ 61,272 (2009). *See also Avista Corp.,* 128 FERC ¶ 61,065 (2009); *Idaho Power Co.,* 128 FERC ¶ 61,064 (2009).

[387] *See* discussion *supra* sections III.A and III.C.

[388] *See* discussion *supra* section III.A.

[389] For example, Entergy's OATT allows Entergy's committee of state regulators to add a project to Entergy's transmission plan upon unanimous vote of the committee members. *See Entergy Arkansas, Inc.,* 133 FERC ¶ 61,211 (2010).

[390] *See* discussion *supra* P 0.

B. Legal Authority for Cost Allocation Reforms

1. Commission Proposal

504. The Commission explained in the Proposed Rule that, to ensure that transmission rates are just and reasonable, the costs of jurisdictional transmission facilities must be allocated in a way that satisfies the ''cost causation'' principle. It noted that the DC Circuit defined the cost causation principle stating that ''it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'' [391] Moreover, the Commission noted that while the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it,[392] the DC Circuit has explained that cost causation ''does not require exacting precision in a ratemaking agency's allocation decisions.'' [393]

505. The Commission explained that, while costs generally have been allocated through voluntary agreements, the cost causation principle is not limited to such arrangements. If it were, the Commission could not address free rider problems associated with new transmission investment and could not ensure that transmission rates are just and reasonable and not unduly discriminatory. The Commission stated that it may determine that an entity is a beneficiary of a transmission facility even if it has not entered a voluntary arrangement with the public utility transmission provider that is seeking to recover the costs of that transmission facility.

506. The Commission noted that it has expressed a willingness to make such a determination, as when presented with concerns about parallel path flow.[394] In such cases, a public utility transmission provider may propose a transmission service rate that would account for unauthorized use of its system.[395] The Commission noted that it has cautioned against the hasty submittal of such unilateral filings and prefers resolution of parallel path flow issues on a consensual, regional basis.[396] If necessary, however, it would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.

507. The Commission also stated that it has affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving MISO and PJM. Specifically, the Commission explained that it directed MISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other's footprint.[397] It subsequently conditionally accepted a proposal by MISO and PJM on the grounds that it ''more accurately identifies the beneficiaries and allocates the associated costs.'' [398]

508. The Commission noted that courts have accepted the application of the cost causation principle in this way. For example, the DC Circuit addressed this issue in connection with a MISO proposal to recover administrative costs through a charge that would apply to transmission loads subject to MISO's OATT rates.[399] The court found that the Commission's system-wide benefits analysis met the requirements of the cost causation principle, that is, to compare ''the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' [400]

2. Comments on Legal Authority

509. Several entities comment in support of the Commission's legal authority to allocate costs of new transmission facilities based on a beneficiary pays approach.[401] AEP asserts that the Commission's proposed cost allocation principles comport with the legal requirements on cost allocation articulated by the U.S. Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission* v. *FERC*.[402] Further, AEP states that while the courts have found that the allocation of transmission expansion costs in rates must follow the ''cost causation'' principle, the courts have explained that all beneficiaries ''cause'' costs for the purpose of applying this principle. Thus, from AEP's perspective, the Commission's proposal to require allocation of costs to beneficiaries is fully consistent with the legal precedent. Iberdrola Renewables and American Transmission agree. American Transmission cautions, however, that care be taken in how precisely the costs of a transmission project are linked to beneficiaries, given that the benefits and beneficiaries of a particular project may change over time, particularly in the case of a large project that provides regional and interregional benefits. Allegheny Energy Companies state that although the *Illinois Commerce Commission* decision found that the Commission did not provide sufficient evidence to justify adoption of the postage-stamp cost allocation method in PJM, it did not reject the method outright, instead requiring the Commission only to provide further justification assuring that this method results in a just and reasonable rate that satisfies the principle that rates required to be paid by a customer must have some relationship to the costs caused or benefits received by that customer.

510. LS Power asserts that there is nothing in the FPA that precludes the Commission from allocating costs incurred by one transmission provider in a region to entities nominally taking service under the tariffs of other transmission providers, or to those other transmission providers themselves for

[391] *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (DC Cir. 1992) (*K N Energy*).

[392] *Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (''We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.'').

[393] *MISO Transmission Owners,* 373 F.3d 1361 at 1371.

[394] The Commission has described the phenomenon of parallel path flow as follows: ''In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself along the lines of least resistance. This parallel path flow is sometimes called 'loop flow.' '' *Indiana Michigan Power Co. and Ohio Power Co.,* 64 FERC ¶ 61,184, at 62,545 (1993).

[395] *See, e.g., Amer. Elec. Power Svc. Corp.,* 49 FERC ¶ 61,377, at 62,381 (1989) (*AEP*).

[396] *Id.; see also Southern California Edison Co.,* 70 FERC ¶ 61,087, at 61,241–42 (1995).

[397] *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168, at P 60 (2004) (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 106 FERC ¶ 61,251, at P 56–57 (2004)). The Commission noted that MISO and PJM had committed in a Joint Operating Agreement to develop such a method for allocating the costs of certain facilities through their joint regional planning committee. *Id.* The Commission did not base the above-noted directive on the existence of the Joint Operating Agreement, which MISO and PJM developed to comply with a previous Commission directive. *See Alliance Cos.,* 100 FERC ¶ 61,137, at P 48, 53 (2002).

[398] *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, at P 10 (2005). *See also Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,102 (2009).

[399] *MISO Transmission Owners,* 373 F.3d 1361. The DC Circuit stated that the subject costs ''are primarily MISO's startup expenses—particularly those pertaining to the MISO Security Center—and certain expenses pertaining to the creation and administration of MISO's open access tariff.'' *Id.* at 1369.

[400] *Id.* at 1367.

[401] *E.g.,* Iberdrola Renewables; 26 Public Interest Organizations; Exelon; ITC Companies; LS Power; and Multiparty Commenters.

[402] 576 F.3d 470 (7th Cir. 2009) (*Illinois Commerce Commission*).

the benefits they receive with respect to their own uses of the regional transmission grid. On the contrary, it explains that allocating costs only to customers located within the corporate boundaries of the utility that owns the transmission facilities will over-allocate costs to such customers and allow other beneficiaries to become free riders. LS Power concludes that the Commission has exclusive jurisdiction over interstate transmission services, and therefore, the authority and the responsibility to define interstate transmission services—here regional transmission services—and to identify the beneficiaries of those services that are responsible for costs incurred by regional transmission providers.

511. Illinois Commerce Commission agrees with the Commission's decision that, when applying the cost causation principle, the Commission may allocate costs of a transmission facility to a beneficiary identified through an appropriate process, such as a Commission-approved transmission planning process, even if that beneficiary has not entered into a voluntary arrangement with a public utility that is seeking to recover the costs of that facility. However, it asserts that the process must take into account the restrictions on allocation to beneficiaries set forth in *Illinois Commerce Commission,* in which cost causers are primary, and beneficiaries may be taken into account only to the extent that, without the developer's expectation of receiving revenues from such a party, the project ''might not have been built, or might have been delayed.'' Illinois Commerce Commission asserts that an unduly discriminatory socialization of costs based on speculation that uncertain future costs will offset the discrimination does not support a finding of just and reasonable rates.[403]

512. A number of commenters agree that a free rider problem exists in transmission development and that the Commission should bring certainty to cost allocation rules to address this concern.[404] NextEra states that any project that provides benefits to entities, other than the sponsoring entity, creates an incentive for an individual beneficiary to defer investment in hopes that others will fund the project's development, and this has led to stalemate and delay. Federal Trade Commission agrees that the lack of rate structures to allocate the costs of needed transmission, and the free rider problem that arises when project beneficiaries seek to shift transmission construction costs onto others, add uncertainty and conflict to the debate over what transmission to build and how to pay for it. Sunflower and Mid-Kansas state that the free rider problem can be an issue regionally, but is likely to prove more intractable for interregional cost allocation. Boundless Energy and Sea Breeze state that cost allocation has to deal with the free rider issue when multiple utilities are involved because then an independent entity with a proposal that provides system benefits across a larger region may find that beneficiaries will not contract for their portion of the benefits.

513. Several commenters argue that it is unlawful for transmission developers to recover costs from entities to which they do not provide service.[405] Some commenters contend that the Commission ignores that privity of contract existed between the entities involved in the cases that it cites to support its proposal[406] and that the Commission's authority under the FPA is premised on a utility having a contractual relationship or a tariff to provide service to its customers.[407] Nebraska Public Power District asserts that the *Mobile-Sierra* cases support this view.[408]

514. Sacramento Municipal Utility District asserts that there is a distinction between allocating costs among a public utility transmission provider's customers without their voluntary agreement (such as the roll-in of the costs of the transmission provider's bulk transmission system) and allocating them to entities that are not the transmission provider's customers. It argues that *AEP* and similar cases[409] do not establish a right to assess costs of facilities to non-customers and that it is a perversion of the statutory scheme to suggest that an entity could build a transmission facility and then claim that because power generated or scheduled by non-customers flowed over the facility, it was entitled to be compensated by them. Southern Companies note that no complaint was filed in response to *AEP,* and the case therefore does not support the idea that allocation of costs to non-customers is lawful. Northern Tier Transmission Group maintains that even if the Commission has authority to permit allocation of costs to an entity that does not take service from the transmission provider that collects the costs, it has not complied with the common law requirements necessary to delegate that authority to transmission providers.

515. Sacramento Municipal Utility District asserts that the cases that the Commission cites dealing with the allocation of costs between RTOs when new facilities in one of their footprints benefits entities in the other's footprint do not apply here.[410] It argues that in those cases, cross-border facility costs were allocated to each RTO as a whole, after which project costs were recovered by the RTO through its own intra-RTO cost allocation. Sacramento Municipal Utility District states that customers in these cases were not being billed for service taken from entities with which those customers had no contract or applicable tariff, but rather were being billed by their own transmission providers.

516. Sacramento Municipal Utility District takes issue with the Commission's reliance on *MISO Transmission Owners* for the proposition that the cost causation principle allows allocation of at least some types of costs to beneficiaries that are not customers of the public utility that is seeking cost recovery. It states that in that case, MISO was the public utility seeking cost recovery, and the costs in question were not levied directly on the entities in question. Instead, the MISO transmission owners—existing customers under the MISO tariff—had challenged whether the cost allocation reflected in their rates was reasonable. Sacramento Municipal Utility District contends that all the court decided was that the Commission had reasonably allocated

[403] In reply, PPL Companies assert that Illinois Commerce Commission overstates *Illinois Commerce Commission,* arguing that the court did not interpret the cost causation principle to require that costs be allocated on a narrow definition of ''cause'' that ignores benefits received by customers.

[404] *E.g.,* Gaelectric North America; Atlantic Grid; Multiparty Commenters; Primary Power; Pennsylvania PUC; NextEra; Federal Trade Commission; Sunflower and Mid-Kansas; Boundless Energy and Sea Breeze; and LS Power.

[405] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Salt River Project; and Sacramento Municipal Utility District.

[406] *E.g.,* Ad Hoc Coalition of Southeastern Utilities (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 144); Salt River Project (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164).

[407] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Salt River; and Nebraska Public Power District.

[408] Nebraska Public Power District (citing *United Gas Pipeline Co.* v. *Mobile Gas Corp.,* 350 U.S. 332 (1955); *FPC* v. *Sierra Pac. Power Co.,* 350 U.S. 348 (1956)).

[409] In addition to *AEP,* Sacramento Municipal Utility District cites *Sierra Pacific Power Co.,* 85 FERC ¶ 61,314 at 62,235 (1998); *Sierra Pacific Power Co.,* 86 FERC ¶ 61,198 at 61,698 (1999); *Vermont Elec. Power Co.,* 44 FERC ¶ 61,098, at 61,275 (1988).

[410] *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084; *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168; *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194.

MISO's operating costs to the transmission owners based on their use of MISO-controlled transmission facilities to deliver power to entities that were not subject to the MISO tariff and on the benefits that MISO Transmission Owners derived from that delivery.[411]

517. Sacramento Municipal Utility District asserts that the Commission's position on joint rates supports its position that a contractual customer relationship is a precondition for the allocation of transmission costs. It states that the Commission's position is that, absent evidence that two systems were in fact acting as one, the Commission cannot mandate the use of a single joint rate. Sacramento Municipal Utility District argues that if the Commission cannot mandate joint rates when this condition is not met even where a customer takes service from both utilities, it cannot mandate that an entity pay rates charged by a utility with which it has no contractual or tariff-based customer relationship.[412]

518. ColumbiaGrid argues that the Commission cannot use its authority to force customers to pay for additional benefits that go beyond their existing service. It states that a court has held that under section 5 of the Natural Gas Act, the Commission may reject unjust and unreasonable rates and prescribe a new just and reasonable rate, but it may not require distributors to accept or to pay for additional service.[413] ColumbiaGrid maintains that this shows that costs cannot be recovered from entities that are not customers receiving jurisdictional service. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the allocation of costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries, and it maintains that the Commission's reliance on this case to extend the cost causation principle to cover any entity that may be said to benefit from a project is misplaced.

519. Southern Companies argue that while the Proposed Rule acknowledges the fundamental role of cost causation, it proceeds to nullify the ''but for'' element that is intrinsic to any determination of cost causation. Southern Companies argue that the primary beneficiary of a transmission improvement is the customer that made the request that ''causes'' the improvement in question. They argue that the Proposed Rule seems to attack cost causation by concluding that a participant funding approach is not permissible.

520. Several commenters maintain that in their experience, free rider problems do not exist and that such concerns may be speculative.[414] Ad Hoc Coalition of Southeastern Utilities states that cost socialization is not needed to protect against the inequities of free ridership. It interprets the Commission's reference to the free rider problem as referring to the relatively cost-free transmission that may be provided to entities that take advantage of oversized investments made by others.

521. Southern Companies suggest that if any such problems exist, they are a product of local or regional factors that do not require a national solution. E.ON argues that free rider problems do not exist in the context of reliability or public policy transmission projects, and participant funding of such projects does not exacerbate the free rider problem.

522. Some commenters argue that, even if free rider problems exist, they can either be solved without resort to broad cost allocation or are beyond the Commission's authority.[415] Alternatively, Illinois Commerce Commission states that while a free rider problem does exist, it is impossible to solve in practice, and the negative consequences of allocating costs too broadly will be greater than allocating costs more narrowly to cost causers and direct, quantifiable beneficiaries. Dominion similarly asserts that while broad cost allocation may eliminate free ridership, it may result in some entities paying disproportionate costs.

523. Alabama PSC states that it would be improper to require citizens of Alabama to pay for the costs of transmission facilities in other areas of the country where there is high congestion and which are not necessary to provide service in Alabama. It maintains that this violates the principle of cost causation and the requirement that facilities be ''used and useful'' before being incorporated into a consumer's rates. Indianapolis Power & Light argues that it is inconsistent with cost causation principles to subsidize a state's generation decisions (*e.g.,* a state's renewable portfolio standard), and states should not be able to pass the cost of compliance with their requirements on to other jurisdictions. ELCON agrees and states that a claim of generalized system benefits, such as an amorphous reliability improvement, does not justify regionalized charges. Instead, ELCON asserts that there must be a tangible, nontrivial benefit supported by substantial evidence. ELCON also maintains that disallowing export charges or other forms of cost transfer to beneficiaries in other planning regions will result in unjust and discriminatory rates.

524. Coalition for Fair Transmission Policy states that the Commission lacks authority to require consideration of broad public policy benefits that cannot be measured or projected within a transmission providers' planning horizon. It maintains that allowing the allocation of costs that are not required to maintain reliability, relieve congestion, or to meet mandated public policy requirements is beyond the Commission's core mission.

525. Ad Hoc Coalition of Southeastern Utilities states that in the Southeast, only North Carolina has a renewable portfolio standards requirement, and there is no suggestion that a regional mechanism for funding transmission is needed to satisfy this requirement. It thus sees no reason to discontinue providing cost recovery for regional transmission projects from the entities that choose to use them.

526. ColumbiaGrid argues that at least with respect to non-RTO regions (where there are no regional service tariff rates), directing public and non-public utilities to adopt a specific cost allocation method in advance could infringe upon a utility's right to propose rates under section 205 of the FPA.[416] The California ISO maintains that the Commission does not have the authority to compel rate filings in the first instance, and it can require a filing only if it shows that the existing rate does not meet the requirements of section 206.[417]

[411] *See also* Southern Companies and ColumbiaGrid.

[412] Sacramento Municipal Utility District cites to *Ft. Pierce Utilities Comm'n* v. *FERC,* 730 F.2d 778 (DC Cir. 1984) (*Fort Pierce*); *Richmond Power & Light* v. *FERC,* 574 F.2d 610 (DC Cir. 1978) (''purchasers are always free to subscribe to the services of willing utilities at the separate rates''); *Alabama Power Co.* v. *FERC,* 993 F.2d 1557, 1565 (DC Cir. 1993) (affirming order directing joint rate between holding company members who the Commission found were acting as one); *see also Illinois Power Co.,* 95 FERC ¶ 61,183, at 61,644 (2002) (approving single joint rate across Alliant and MISO systems but recognizing that, in the absence of an agreement between these utilities, there would not be a single rate).

[413] ColumbiaGrid cites to *Exxon Mobil Corp.* v. *FERC,* 430 F.3d 1166 (DC Cir. 2005) (*Exxon Mobil Corp.*).

[414] *E.g.,* Southern Companies; California Municipal Utilities; Transmission Agency of Northern California; and Columbia Grid.

[415] *E.g.,* Nebraska Public Power District and Sacramento Municipal Utility District.

[416] ColumbiaGrid bases this claim on *Atlantic City Electric Co.* v. *FERC,* 295 F.3d 1 (DC Cir. 2002) (*Atlantic City*).

[417] Similarly, Northern Tier Transmission Group argues that the Commission must justify, under

California ISO argues that the Commission cannot fulfill this requirement with regard to cost allocation for regional and interregional facilities because there are no existing contracts or rates for such services. The Commission may at most issue guidance on whether future filings will meet statutory requirements.

527. Southern Companies assert that where vertically integrated transmission providers plan their transmission systems from the bottom up under state supervision and recover most of their costs for transmission facilities through bundled rates, the Proposed Rule's mandates cannot be implemented without preempting or undermining state law. Southern Companies state that the Commission should revise its proposed reforms and explain how they can be implemented while respecting existing processes for bundled retail ratemaking. Southern Companies assert that they recover only approximately 15 percent of their transmission revenue requirements under a federal OATT, with the remaining 85 percent being recovered in state-regulated bundled rates. They state that the latter cost recovery is not an issue of federal comparability, and a nonincumbent would, at best, be allowed to recover only 15 percent of its transmission costs under a federal OATT, with the rest requiring state approval. Southern Companies maintain that as a practical matter, a nonincumbent cannot have ''comparable'' cost recovery without a long-term contract from Southern Companies that has appropriate state commission approval for purposes of retail rate recovery.

528. Transmission Access Policy Study Group urges the Commission to address allocation of costs of transmission projects that go beyond existing boundaries of an RTO or individual transmission providers where the transmission grid is integrated. It recommends that the Commission recognize that it has the authority to order joint, non-pancaked rates where transmission systems are integrated. Sacramento Municipal Utility District argues in response that the Commission cannot require joint rates unless two adjoining transmission systems are not just integrated, but effectively operate as a single system. Large Public Power Council agrees. Ad Hoc Coalition of Southeastern Utilities argues that the statutory right of utilities to set their rates may not be easily set aside, and that imposing a joint, non-pancaked rate structure on utilities would do exactly that.

section 206, modifying the cost allocation process that it already accepted for its members.

529. Florida PSC is concerned that the Commission's proposal may circumvent its authority over rates for transmission infrastructure that serves retail load because the Proposed Rule appears to allow entities seeking to construct merchant transmission projects to recover project costs from Florida ratepayers through a Commission-approved cost allocation process. North Carolina Agencies argue that the Final Rule should recognize the indispensible role of state regulatory authorities and should apply only to unbundled transmission rates. Northwestern Corporation (Montana) states that entities seeking to recover costs without approval from state public utilities commissions face the risk of cost disallowance.

3. Commission Determination

530. We conclude that we have the legal authority to adopt the cost allocation reforms required by this Final Rule. Numerous commenters challenge our authority to require allocation of transmission costs to beneficiaries that do not have a contractual or formalized customer relationship with the entity that is collecting the costs. These challenges are based primarily on the commenters' analysis of various Commission and court cases. Some commenters have made arguments that speak directly to provisions of the FPA, but none of these assertions reach convincing conclusions. For instance, Ad Hoc Coalition of Southeastern Utilities states that ''[u]tilities filing for rate changes under FPA section 205 ask the Commission to approve changes in rates charged *to their customers*'' and that ''the Commission's authority is, in all cases, based on the premise that a utility has a contractual relationship to provide service to its customers.'' [418] However, section 205 does not specify any such limitation and no commenter has shown where it is expressed elsewhere in the FPA. Instead, commenters generally appear to agree with Ad Hoc Coalition of Southeastern Utilities that the ''FPA is structured on the *assumption* that rates subject to [Commission] approval are supported by a contractual agreement.'' [419]

531. The merit of this argument depends, of course, on how the FPA is in fact structured, and an examination of the relevant provisions of the statute shows that it is not structured in a way that would justify this argument. On the contrary, the Commission's jurisdiction is clearly broad enough to allow it to ensure that all beneficiaries of services provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. As discussed further below, this comports fully with the specific characteristics of transmission facilities and transmission services, and our actions today are necessary to fulfill our statutory duty of ensuring rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. We thus turn first to the language of the statute itself.

[418] Ad Hoc Coalition of Southeastern Utilities Comments at 60–61 (emphasis in original).

[419] *Id.* at 60 (emphasis supplied).

532. Section 201(b)(1) of the FPA gives the Commission jurisdiction over ''the transmission of electric energy in interstate commerce.'' The Commission's jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements. Moreover, section 201(b)(1) gives the Commission jurisdiction over ''all facilities'' for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions. As a result, the Commission has jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities.

533. Neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. These statutory provisions speak of rates and charges that are ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' by a public utility. Any such rates or charges must, of course, be accepted for filing with the Commission under either section 205 or 206, but nothing in these sections precludes flows of funds to public utility transmission providers through mechanisms other than agreements between the service provider and the beneficiaries of those transmission facilities.

534. Transmission services create an opportunity for free ridership because the nature of power flows over an interconnected transmission system does not permit a public utility

transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them. The Commission expressed concern over free ridership in Order No. 890, where it noted that ''there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it.'' [420]

535. In Order No. 890, the Commission recognized that the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them. We conclude now that this principle cannot be limited to voluntary arrangements because if it were ''the Commission could not address free rider problems associated with new transmission investment, and it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory. In fact, the courts have recognized this aspect of cost causation quite independently of an analysis of the scope of our statutory jurisdiction over transmission.

536. The courts have acknowledged that cost causation involves ''comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' [421] An approach to cost causation that is limited to voluntary arrangements such as participant funding has the effect of ''focusing us on the most immediate and proximate cause of the cost incurred,'' and it precludes looking ''at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign[ing] them liability too.'' [422] In short, a full cost causation analysis may involve ''an extension of the chain of causation'' [423] beyond those causes captured in voluntary arrangements. In other words, to identify all causes, we must to some degree begin with their effects, *i.e.,* the benefits that they engender and then work back to their sources.

537. This point was acknowledged in the Seventh Circuit's characterization of cost causation in *Illinois Commerce Commission.* The Seventh Circuit states 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,* as without the expectation of its contributions the facilities might not have been built, or might have been delayed.[424]

The court fully recognized that, to identify causes of costs, one must to some degree begin with benefits. ColumbiaGrid argues that *Illinois Commerce Commission* does not support the Commission's position on cost allocation because the statement just cited is preceded by the statement that ''[A]ll *approved* rates [must] reflect to some degree the costs actually caused by the customer who must pay them.'' [425] ColumbiaGrid maintains that this demonstrates the *Illinois Commerce Commission* ''does not support the [Proposed Rule's] approach of allocating costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries.'' [426] What this argument fails to recognize is that the point ColumbiaGrid contests was not before the court in *Illinois Commerce Commission,* and the Commission's jurisdiction over transmission, as outlined above, is broad enough to approve rates based on the court's characterization of cost causation.[427] In other words, there is nothing in what the court said that can be viewed as preventing the Commission from dealing with the free rider problem. Indeed, by emphasizing the relationship between beneficiaries identified and cost allocation, the court's ruling supports greater attention to that issue. Finally, we note that under this Final Rule, transmission planning regions are not required to analyze the distribution of benefits on an entity-by-entity basis; nothing in this Final Rule precludes the regions from doing so, provided that they satisfy the cost allocation principles adopted herein. We now turn to other individual comments that involve these issues.

538. Southern Companies' argument that the primary beneficiary of a transmission facility is the customer that made the request that causes the improvements to be planned and constructed tends to blur the distinction between benefits and burdens. As discussed above, the courts have acknowledged that distinction as relevant to cost allocation and the requirements in this Final Rule are consistent with that distinction. To the extent that commenters are supporting participant funding as a regional cost allocation method, we address those comments below.[428]

539. We disagree with Sacramento Municipal Utility District and Southern Companies that *AEP* applies only in exceptional circumstances and does not support our position here. In that case, the Commission expressed a preference for a voluntary resolution of the problem that loop flow represented, a position that is consistent with our findings here. The Commission's authority is not limited in principle by cases where the Commission expresses a preference not to exercise that authority. We also disagree with Sacramento Municipal Utility District that our reforms represent a perversion of the statutory scheme in which an entity could build a transmission facility and then simply claim a right to payment for benefits from beneficiaries with which it has no contractual or tariff relationship. As we state above, the Commission's jurisdiction is broad enough to allow it to ensure that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities. Our cost allocation reforms are tied to our transmission planning reforms, which require that, to be eligible for regional cost allocation, a proposed new transmission facility first must be selected in a regional transmission plan for purposes of cost allocation, which depends on a full assessment by a broad range of regional stakeholders of the benefits accruing from transmission facilities planned according to the reformed transmission planning processes. As such, the public utility transmission providers in the regional

[420] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 561.

[421] *MISO Transmission Owners,* 373 F.3d 1361, at 1368 (internal citations omitted).

[422] *KN Energy,* 968 F.2d 1295 at 1302.

[423] *Id.*

[424] *Illinois Commerce Commission,* 576 F.3d 470 at 476 (emphasis supplied).

[425] ColumbiaGrid Comments at 29 (citing *Illinois Commerce Commission,* 576 F.3d 470 at 476 (emphasis supplied by ColumbiaGrid)).

[426] *Id.*

[427] This point applies equally to Sacramento Municipal Utility District's objection that the other Commission and court cases pertaining to MISO cited in the Proposed Rule are not on point because they involve instances where a customer relationship of some type had already been established, and that all that these cases dealt with was whether an allocation was just and reasonable. When Sacramento Municipal Utility District states that ''the cost allocation methods approved by FERC in the MISO cases rested on the understanding that 'the ultimate costs allocated to [MISO] or PJM for a so-called cross-border allocation project will be recovered by each RTO pursuant to the applicable provisions of their tariffs,' '' it is ignoring substance in favor of form. It is focusing on the formal mechanisms through which costs are collected, not the underlying substance of the cost allocation itself. *See* Sacramento Municipal Utility District Comments at 14 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194 at P 4). The mechanism for recovering a rate does not change the identity of the provider who is in fact recovering it.

[428] *See* discussion *infra* section IV.F.2.

transmission planning process identify the beneficiaries who will pay for the costs of the new transmission facility selected in a regional plan for purposes of cost allocation.

540. The fact that the Commission has supported parts of its argument through reference to cases in which privity of contract existed between public utilities and the entities from which costs were recovered does not affect this conclusion.[429] This issue was not before the court in any of these cases, and therefore the mere existence of privity of contract does not demonstrate the necessity of privity. In response to Nebraska Public Power District, we do not agree that the *Mobile-Sierra* doctrine has applicability here. We are dealing here with conditions under which costs can be recovered in rates, not conditions under which existing contracts rates can be altered.

541. Contrary to ColumbiaGrid's position, *Exxon Mobil Corp.* does not apply here. As ColumbiaGrid states, in *Exxon Mobil Corp.* the court held that the Commission may not require distributors to accept or pay for additional service.[430] Unlike the situation addressed in *Exxon Mobil Corp.,* the requirements of this Final Rule with respect to cost allocation do not ''impose'' any new service on beneficiaries.

542. We also note that our position on joint rates does not have any relevance here. The fact that the Commission cannot require two public utilities to charge a joint rate without evidence that their two systems are in fact acting as one does not preclude the Commission from permitting a single public utility to recover its costs from beneficiaries of the transmission facilities identified in the transmission planning process regardless of the formal customer relationships that exist prior to the time that cost allocation is authorized. We do not see how the conditions under which a joint rate can be imposed has any implications for the range of beneficiaries from which a single public utility can recover the costs of its transmission services, even when combined with recovery by other public utilities of related transmission facilities.

543. We disagree with Northern Tier Transmission Group that we are delegating any authority to transmission providers. All proposed cost allocation methods will be subject to Commission approval, and all specific allocations will be incorporated in rates that must be filed with and accepted by the Commission.

544. We agree with the Alabama PSC that citizens of Alabama should not be responsible for costs of transmission facilities from which they derive no benefits. Indeed, the Commission specified in the Proposed Rule as a principle of regional cost allocation that ''[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.''[431] With respect to interregional transmission coordination, the Commission specified that a ''transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.''[432] In addition, ''[c]osts cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located.''[433] These cost allocation principles are adopted in this Final Rule, and its requirements thus conform fully with the position taken by the Alabama PSC.

545. Contrary to the claims of Indianapolis Power & Light, the reforms instituted in this Final Rule neither authorize nor will lead to subsidization of generation decisions by different states. Beneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state's transmission needs driven by Public Policy Requirements. If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits because Public Policy Requirements played a role in the decision to construct the transmission facility. We agree with ELCON that estimations of benefits require adequate support. We note, however, that benefits are not ''amorphous'' simply because costs are to be allocated ''in a manner that is roughly commensurate with estimated benefits.''[434] The courts have acknowledged the natural limits that accompany estimations made in the cost-allocation process.[435]

546. We disagree with Coalition for Fair Transmission Policy that the Proposed Rule can be read to imply that the Commission may require consideration of broad policy goals that are far afield from the Commission's core mission. This Final Rule requires that public utility transmission providers establish a process for identifying those transmission needs driven by Public Policy Requirements that are to be considered in the transmission planning process.[436] In doing this, we are simply acknowledging that such Public Policy Requirements are facts that may have consequences in the form of increasing or decreasing the demand for additional transmission facilities. We are not straying from our core mission when we acknowledge that these facts will affect matters that are central to that mission and accordingly require that they be considered in the transmission planning process, nor are we promoting any particular public policy by requiring a process to determine what, if any, transmission needs are driven by a Public Policy Requirement.[437]

547. Directing a public utility transmission provider to adopt a specific cost allocation method or methods in advance does not infringe upon a utility's right to propose rates under section 205 of the FPA. It simply requires that rate filings meet certain standards. ColumbiaGrid cites *Atlantic City* as supporting the contrary position. In that case, the court held that the Commission could not require that the PJM Transmission Owners Agreement be modified to eliminate a provision that allowed a public utility transmission owner to make a unilateral filing to make changes in rate design or terms and conditions of jurisdictional services. The court held that public utilities have an express right under section 205 to make such filings, and the Commission could not require them to relinquish it.[438] Nothing in this Final Rule has the effect of disenfranchising any individual or entity of rights under

[429] *See Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168; *Alliance Cos.,* 100 FERC ¶ 61,137.

[430] *See Exxon Mobil Corp.,* 430 F.3d 1166, 1176–77 (DC Cir. 2005).

[431] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

[432] *Id.* P 174.

[433] *Id.*

[434] The Commission discusses in detail the application of this cost allocation principle below.

[435] *Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (''We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.''). *See also MISO Transmission Owners,* 373 F.3d 1361 at 1369 (''we have never required a ratemaking agency to allocate costs with exacting precision.''); *Sithe,* 285 F.3d 1 at 5.

[436] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 4.

[437] *See* discussion *supra* section III.A.4.

[438] *Atlantic City,* 295 F.3d 16, at 21 (DC Cir. 2002).

section 205 to make filings. The Commission regularly establishes standards for filings under section 205, and doing so does not negate any rights under that section.

548. In response to those commenters that argue that our cost allocation reforms will affect existing state jurisdiction over utility rates, it is not clear why cost allocations consistent with this Final Rule would affect state jurisdiction differently from existing cost allocations. In any event, we find that such arguments are premature. It is inappropriate for the Commission to decide such issues generically in a rulemaking, as such issues should be decided based on specific facts and circumstances, none of which are presented here.

549. In response to Transmission Access Policy Study Group, we note that the issue of joint rates is beyond the scope of this proceeding. This Final Rule requires the development of cost allocation methods for regional and interregional transmission facilities in connection with its planning reforms. As described in the cases that commenters cite in their responses to Transmission Access Policy Study Group, the issue of joint, non-pancaked rates involves matters that are considerably broader than our transmission planning-based cost allocation reforms. The Commission will consider any calls for joint, non-pancaked rates on a case-by-case basis and in accordance with the principles established in these cases.

C. Cost Allocation Method for Regional Transmission Facilities

1. Commission Proposal

550. The Proposed Rule would require that every public utility transmission provider develop a method, or set of methods, for allocating the costs of new transmission facilities that are included in the transmission plan produced by the transmission planning process in which it participates. If the public utility transmission provider is an RTO or ISO, then the method or methods would be required to be set forth in the RTO or ISO tariff. In other transmission planning regions, each public utility transmission provider would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region. This method or methods would have to satisfy six regional cost allocation principles, discussed below.

551. These regional cost allocation principles would apply only to the cost allocation method or methods for new transmission facilities selected in the regional transmission plan produced by the transmission planning process in which the public utility transmission provider participates. The Commission also stated that it did not intend to require a uniform cost allocation method that every region must adopt to allocate the costs of new regional transmission facilities that are eligible for cost allocation, but instead recognized that regional differences may warrant distinctions in cost allocation methods among transmission planning regions.[439]

552. The Commission stated in the Proposed Rule that with regard to a new transmission facility that is located entirely within one transmission owner's service territory, a transmission owner may not unilaterally invoke the regional cost allocation method to require the allocation of the costs of a new transmission facility to other entities in its transmission planning region. However, if the regional transmission planning process determines that a new facility located solely within a transmission owner's service territory would provide benefits to others in the region, allocating the facility's costs according to that region's regional cost allocation method or methods would be permitted.[440]

2. Comments on Cost Allocation Method in Regional Transmission Planning

553. A number of commenters generally support the Commission's proposal.[441] For example, ITC Companies support the promulgation of a comprehensive, holistic cost allocation method generally applicable to new transmission facilities, citing SPP's highway/byway mechanism as a model.[442]

554. Other commenters express concern with the Commission's proposal to require the development of a cost allocation method for transmission facilities included in a regional transmission plan.[443] Bonneville Power asserts that mandatory regional cost allocation is not necessary to build new transmission in the Pacific Northwest, and such a requirement will lead to extended disputes and greater uncertainty. Bonneville Power contends that instead, voluntary participation, including participation in open seasons, is the best way to encourage the development of new transmission for renewables in the Pacific Northwest. California Commissions echo the sentiment that cost allocation has generally not been a major barrier to entry for new transmission in the West. California Commissions are concerned that the Commission may do more harm than good by moving aggressively and prescriptively on regional cost allocation methods that are not necessarily needed to support transmission development.

555. Some commenters, such as Bonneville Power, California ISO, and Western Area Power Administration, express a preference for voluntary coordination and cost allocation of transmission facilities rather than mandatory cost allocation rules. Coalition for Fair Transmission Policy urges the Commission to consider whether it is prudent in all cases to require the filing of regional cost allocation methods by transmission providers in advance of projects being proposed, as not every project will fit into a particular model, and adherence to strict rules may deter rather than encourage the construction of needed new transmission facilities.

556. New York PSC indicates that it is uncertain as to whether the Commission intends to utilize a pre-established cost allocation methodology as an automatic right of cost recovery. Therefore, New York PSC requests that the Commission clearly indicate when a project would be entitled to cost recovery relative to receiving a cost allocation. Western Grid Group shares the view that the distinction between cost allocation and cost recovery is a pertinent issue. Arizona Public Service Company raises concerns about cost recovery in regions where no regional tariff mechanisms exist. In the absence of such a cost recovery solution, Arizona Public Service Company states that the Commission should not place the burden of recovery for third party developers on incumbent utilities that may be required to seek such recovery

[439] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 165.

[440] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 169.

[441] *E.g.,* MidAmerican; American Transmission; Clean Line; Dominion; East Texas Cooperatives; MISO; National Grid; NEPOOL; New York ISO; Multiparty Commenters; and WIRES.

[442] The arguments in support of this proposal are implicit in the comment summaries under the discussion of other cost allocation proposals below. *See* discussion *infra* section 0. The term ''highway/byway'' refers to regionwide allocation of the cost of a new high voltage transmission facility and the allocation of the cost of a new lower voltage transmission facility to a defined portion of the region. *See Southwest Power Pool, Inc.,* 131 FERC ¶ 61,252 (2010).

[443] *E.g.,* Bonneville Power Administration; California Commissions; Eastern Massachusetts Consumer-Owned System; Xcel; and Western Area Power Administration.

through state commissions for facilities that the incumbent utilities have not built and for which the incumbent utilities may be unable to show benefit for their ratepayers.

557. MISO Transmission Owners agree that a transmission provider should not be able to invoke the regional cost allocation method unilaterally for a facility located entirely within its own service territory. However, they state that in the RTO context, facilities located solely within one transmission owner's service territory should be allocated in accordance with the Commission-accepted cost allocation method. MISO Transmission Owners state that the Proposed Rule should not be interpreted to indicate that single-zone facilities are no longer eligible for regional cost allocation if such allocation is permitted under an RTO or ISO tariff. Additionally, MISO Transmission Owners argue that the Commission should not permit this requirement to allow attempts to relitigate existing cost allocation method that apply to intra-zonal transmission facilities.

3. Commission Determination

558. We require that a public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. If the public utility transmission provider is an RTO or ISO, then the cost allocation method or methods must be set forth in the RTO or ISO OATT. In a non-RTO/ISO transmission planning region, each public utility transmission provider located within the region must set forth in its OATT the same language regarding the cost allocation method or methods used in its transmission planning region. In either instance, such cost allocation method or methods must be consistent with the regional cost allocation principles adopted below.

559. We conclude that these regional transmission cost allocation requirements are necessary to ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. In the absence of clear cost allocation rules for regional transmission facilities, there is a greater potential that public utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs. Conversely, greater certainty as to the cost allocation implications of a potential transmission project will enhance the ability of stakeholders in the regional transmission planning process to evaluate the merits of the transmission project. Moreover, as we have established above, there 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.

560. We do not specify here how the costs of an individual regional transmission facility should be allocated. However, while each transmission planning region may develop a method or methods for different types of transmission projects, such method or methods should apply to all transmission facilities of the type in question. Although we allow a different method or methods for different types of transmission facilities, as discussed below regarding regional Cost Allocation Principle 6, if public utility transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each method would have to be determined in advance for each type of facility.

561. We disagree with California Commissions that our actions here are too aggressive and prescriptive and with Bonneville Power that adopting a mandatory cost allocation method will lead to extended disputes and greater uncertainty. We have stressed throughout this proceeding that we intend to be flexible and are open to a variety of approaches to compliance. By imposing the cost allocation requirements adopted here, the Commission seeks to enhance certainty for developers of potential transmission facilities by identifying, up front, the cost allocation implications of selecting a transmission facility in the regional transmission plan for purposes of cost allocation. This does not undermine the ability of market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or methods. Indeed, market participants may be in a better position to undertake such negotiations as a result of the public utility transmission providers in the region having evaluated a transmission project. The results of that evaluation, including the identification of potential beneficiaries of the transmission project, could facilitate negotiations among potentially interested parties.

562. In response to Coalition for Fair Transmission Policy, we require the development of a cost allocation method or a set of methods in advance of particular transmission facilities being proposed so that developers have greater certainty about cost allocation and other stakeholders will understand the cost impacts of the transmission facilities proposed for cost allocation in transmission planning. The appropriate place for this consideration is the regional transmission planning process because addressing these issues through the regional transmission planning process will increase the likelihood that transmission facilities selected in regional transmission plans for purposes of cost allocation are actually constructed, rather than later encountering cost allocation disputes that prevent their construction.

563. With regard to comments regarding matters of cost recovery, we acknowledge that cost allocation and cost recovery are distinct. This Final Rule sets forth the Commission's requirements regarding the development of regional and interregional cost allocation methods and does not address matters of cost recovery. We disagree with Arizona Public Service Company, however that incumbent utilities may be unreasonably burdened by the potential of cost allocation for transmission facilities developed by third party developers. For any proponent of a transmission facility, whether an incumbent or a nonincumbent, to have the costs of a transmission facility allocated through the regional cost allocation method or methods, its transmission facility first must be selected in the regional transmission plan for purposes of cost allocation. This in turn requires a determination that the transmission project is an efficient or cost-effective solution pursuant to the processes the transmission providers in the region have put in place, including consultation with stakeholders. Therefore, the benefits of any such transmission project should have been clearly identified prior to the allocation of any related costs.

564. With respect to cost allocation for a proposed transmission facility located entirely within one public utility transmission owner's service territory, we find that a public utility transmission owner may not unilaterally apply the regional cost allocation method or methods developed pursuant to this Final Rule. However, a proposed transmission facility located entirely within a public utility transmission owner's service territory could be determined by public utility transmission providers in the region to provide benefits to others in the region and thus the cost of that transmission facility could be allocated according to

that region's regional cost allocation method or methods.

565. In response to MISO Transmission Owners' concerns regarding relitigation of existing Commission-approved transmission cost allocation methods, the Commission declines here to prejudge whether any such existing cost allocation methods comply with the requirements of this Final Rule. To the extent MISO Transmission Owners believe that to be the case with their region, they may take such positions during the development of compliance proposals and during Commission review of compliance filings. However, we reiterate here that our cost allocation reforms apply only to new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation and, therefore, do not provide grounds for relitigation of cost allocation decisions for existing transmission facilities.

D. Cost Allocation Method for Interregional Transmission Facilities

1. Commission Proposal

566. The Proposed Rule would require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new interregional transmission facility between the two neighboring transmission planning regions in which the facility is located or among the beneficiaries in the two neighboring transmission planning regions. This common method would have to satisfy six interregional cost allocation principles, discussed below.

567. The Commission stated in the Proposed Rule that it would not apply the interregional cost allocation principles so as to require every pair of regions to adopt the same uniform approach to cost allocation for new interregional transmission facilities, but instead recognized that there may be legitimate reasons for the public utility transmission providers located in different pairs of neighboring transmission planning regions to adopt different cost allocation methods.[444]

2. Comments on Interregional Cost Allocation Reforms

568. A number of commenters generally support the proposal that each transmission provider have an interregional cost allocation method for facilities located in more than one region.[445] NEPOOL states that it generally supports the proposal to require formal agreements between neighboring control areas that contain cost allocation methods for interregional projects, with such methods being subject to the principles specified in the Proposed Rule. East Texas Cooperatives support the application of the six proposed principles to interregional cost allocation methods. AEP states that getting these ground rules in place is essential to move forward on major interregional projects and to break down decades old barriers to these types of projects. Likewise, MidAmerican states that there is little if any coordination of transmission cost allocation between MISO and SPP regions and the MISO and MAPP regions and, as such, supports the Commission's efforts to create a more coordinated and effective way to allocate costs of new transmission facilities both within these planning regions and those linking adjacent planning regions.

569. Vermont Electric states that it welcomes the proposed requirement for interregional coordination and the Commission's attention to what it views as deficiencies in the ISO New England transmission planning process. Vermont Electric states that the Commission's proposed requirement for a standard cost allocation method applicable to interregional projects would prevent delays, reduce costs for project developers, and facilitate development of potentially valuable interregional projects.

570. A number of commenters question or express concern about the appropriateness of requiring the development of interregional cost allocation methods for future interregional transmission facilities in advance of a proposal for a specific interregional facility.[446] For example, SoCal Edison notes that voluntary coordination efforts are underway, and it argues that there is no reason to impose additional mandatory interregional coordination criteria or requirements. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. ISO New England also states that the Final Rule should either clarify the manner in which agreement on cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

571. National Grid believes that interregional coordination agreements should include general cost allocation principles that will apply to interregional projects, but that it would not be beneficial to prescribe an interregional cost allocation method in advance of a specific interregional project. Similarly, New England Transmission Owners and New York Transmission Owners contend that, in light of the limited number of projects that are likely to be identified through interregional coordination, the Commission should allow cost allocation issues to be decided in connection with individual projects instead of dictating a generic cost allocation method in advance.

572. Vermont Electric agrees, suggesting that the Commission impose an interregional requirement only to the extent regional planning organizations do not respond promptly and effectively to cost allocation issues applicable to interregional projects on a case-by-case basis. New York ISO recommends that the Commission require neighboring regions to include language in their tariffs setting forth their obligation to negotiate cost allocation rules for any interregional projects that are approved in their respective planning processes and that such rules must comply with the cost allocation principles established in the Final Rule.

573. Similarly, Transmission Agency of Northern California cautions against requiring the development of cost allocation principles between planning regions prior to the need for such coordination. California ISO and Indianapolis Power & Light also argue that the requirement for a mandatory advanced agreement on cost allocation before knowing the specific facts and circumstances of an interregional project is neither appropriate nor effective. Indianapolis Power & Light also states that it would be better to postpone development of such agreements until a specific interregional project has been proposed.

574. California ISO states that the Commission should not mandate an interregional cost allocation method or methods because the existing case-by-case determination of cost allocation for interregional transmission facilities has worked well in the West. California ISO states that different parties will bring different interests to the table, and different circumstances may warrant different approaches to interregional cost allocation. However, California ISO states that regardless of what the

[444] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 175.

[445] *E.g.,* AEP; Clean Line; MidAmerican; MISO; MISO Transmission Owners; NEPOOL; New England States Committee on Electricity; Northeast Utilities; Pennsylvania PUC; PSEG Companies; and Energy Consulting Group.

[446] *E.g.,* New York ISO; Coalition for Fair Transmission Policy; California ISO; and National Grid.

Commission concludes on this issue, it should retain in the Final Rule the concept that inclusion of an interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to applying an interregional cost allocation principle.[447] California ISO argues that this is necessary to ensure equitable cost allocation.

575. Edison Electric Institute states that flexibility is especially important for multistate projects with a large number of likely beneficiaries. It states that flexibility also is important for different regions in developing interregional cost allocation methods, including methods that provide for a case-by-case evaluation of projects in lieu of using prescribed cost allocation formulas. Edison Electric Institute states that the Commission should allow a region to propose the evaluation of alternative cost-effective projects that would result in lower costs to the region's consumers.

576. Edison Electric Institute also asks the Commission to be clear in the Final Rule about whether and how existing interregional cost allocation mechanisms and those under development in various regions will be affected, if at all. Transmission Dependent Utility Systems and Xcel support the proposed requirement, but request that the Commission not disrupt or disturb the methods already in place. New England Transmission Owners state that the Commission should permit New England and New York to move forward to develop coordinated interregional coordination based on the principles in their current agreement.

577. SPP seeks clarification, consistent with Order No. 890, that transmission owning members of RTOs and ISOs can comply with the proposed interregional cost allocation mandates through their participation in the RTO or ISO and the interregional agreements executed by the RTO or ISO, rather than requiring them to negotiate with their neighbors to develop separate arrangements.

3. Commission Determination

578. We require a public utility transmission provider in a transmission planning region to have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located.[448] As we discuss further below, the cost allocation method or methods used by the pair of neighboring transmission regions can differ from the cost allocation method or methods used by each region to allocate the cost of a new interregional transmission facility within that region. For example, region A and region B could have a cost allocation method for the allocation of the costs of an interregional transmission facility between regions A and B (the interregional cost allocation method) that could differ from the respective regional cost allocation method that either region A or region B uses to further allocate its share of the costs of an interregional transmission facility. In an RTO or ISO region, the method must be filed in the OATT. In a non-RTO/ISO transmission planning region, the common cost allocation method or methods must be filed in the OATT of each public utility transmission provider in the transmission planning region. In either instance, such cost allocation method or methods must be consistent with the interregional cost allocation principles adopted below.

579. As with our regional cost allocation requirements above, we are requiring interregional cost allocation requirements to remove impediments to the development of transmission facilities that are identified as needed by the relevant regions. We conclude that the absence of clear cost allocation rules for interregional transmission facilities can impede the development of such transmission facilities due to the uncertainty regarding the allocation of responsibility for associated costs. This may, in turn, adversely affect rates for jurisdictional services, causing them to become unjust and unreasonable or unduly discriminatory or preferential.

580. As in the case of regional cost allocation, we do not require a single nationwide approach to interregional cost allocation but instead allow each pair of neighboring regions the flexibility to develop its own cost allocation method or methods consistent with the interregional cost allocation principles adopted in this Final Rule. We also clarify that we do not require each transmission planning region to have the same interregional cost allocation method or methods with each of its neighbors. Each pair of transmission planning regions may develop its own approach to interregional cost allocation that satisfies both transmission planning regions' needs and concerns, as long as that approach satisfies the interregional cost allocation principles. Our intention is to preserve the ability of each pair of transmission planning regions to plan for future development of interregional transmission projects that will be beneficial to both transmission planning regions.

581. We do not specify here how the costs for an individual interregional transmission facility should be allocated. However, while transmission planning regions can develop a different cost allocation method or methods for different types of transmission projects, such a cost allocation method or methods should apply to all transmission facilities of the type in question. Although we allow a different cost allocation method or methods for different types of transmission facilities, as discussed below regarding Interregional Cost Allocation Principle 6, if public utility transmission providers choose to propose a different cost allocation method or methods for different types of transmission facilities, each cost allocation method would have to be determined in advance for each type of transmission facility. Also, we adopt the requirement that an interregional transmission facility must be in the relevant regional transmission plans to be eligible for interregional cost allocation pursuant to the interregional cost allocation method or methods.

582. Additionally, a central underpinning to our reforms in this Final Rule is the closer alignment of transmission planning and cost allocation. As we discuss above in the section on interregional transmission coordination,[449] an interregional transmission facility must be selected in both of the relevant regional transmission planning processes for purposes of cost allocation in order to be eligible for interregional cost allocation pursuant to a cost allocation method required under this Final Rule. This is designed, among other things, to allow for adequate stakeholder review of the interregional transmission facility before the relevant portion of the facility is in a regional transmission plan.[450] This process could be undermined if a transmission facility that is located and

[447] *See also, e.g.,* Connecticut & Rhode Island Commissions.

[448] A group of three or more transmission planning regions within an interconnection—or all of the transmission planning regions within an interconnection—may agree on and file a common method or methods for allocating the costs of a new interregional transmission facility. However, the Commission does not require such multiregional provisions among more than two neighboring transmission planning regions.

[449] *See* discussion *supra* section III.C.

[450] *See* discussion *supra* section III.C.

reviewed only within one regional transmission planning process, could nevertheless have its costs allocated to potential beneficiaries in another region that may not have had an adequate opportunity to review the need for the transmission facility and make the resulting beneficiary determinations. As we make clear in our discussion of Cost Allocation Principle 4,[451] costs may be assigned on a voluntary basis under this Final Rule to a transmission planning region in which an interregional transmission facility is not located. Given this option, regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.

583. With respect to existing interregional transmission coordination and cost allocation agreements, we do not opine here on whether such agreements satisfy the interregional transmission coordination requirements and cost allocation principles of this Final Rule.[452] To the extent that a public utility transmission provider believes such an agreement satisfies these requirements in whole or in part, that public utility transmission provider should describe in its compliance filing how the relevant requirements are satisfied by reference to tariff sheets on file with the Commission.

584. We also clarify in response to commenters that the requirement to coordinate with neighboring regions applies to public utility transmission providers within a region as a group, not members within an RTO or ISO acting individually. Therefore, within an RTO or ISO, the RTO or ISO would develop an interregional cost allocation method or methods with its neighbors on behalf of its public utility transmission owning members.

E. Principles for Regional and Interregional Cost Allocation

1. Use of a Principles-Based Approach

a. Commission Proposal

585. For the cost allocation method or methods to be just and reasonable and not unduly discriminatory or preferential, the Proposed Rule would require that each cost allocation method satisfy six general cost allocation principles, as set out in the following subsections. The Commission proposed six regional cost allocation principles for each cost allocation method for regional transmission facilities included in the regional transmission plan for purposes of cost allocation and six analogous interregional cost allocation principles for each cost allocation method for a new transmission facility that is located in two neighboring transmission planning regions and is accounted for in the interregional transmission coordination process.

586. Specifically, the Proposed Rule would require that each RTO or ISO (on behalf of its transmission owning members) or the individual public utility transmission providers in a non-RTO/ISO transmission planning region to demonstrate through a compliance filing that its cost allocation method or methods for new transmission facilities satisfy the following regional cost allocation principles:

(1) The cost 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.[453] In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.[454]

(2) Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.

(3) If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio.

(4) The allocation method for the cost of a regional facility 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.[455] However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this Final Rule.[456]

587. The Proposed Rule required each cost allocation method to comply with the following interregional cost allocation principles:

(1) The costs of a new interregional facility must be allocated to each transmission planning region in which that facility is located in a manner that is at least roughly commensurate with the estimated benefits of that facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.

(2) A transmission planning region that receives no benefit from an interregional

[451] *See* discussion *infra* section IV.E.5.

[452] Public utility transmission providers may continue to enter into such agreements as a means of complying with this Final Rule, but any such agreements that are incorporated into the public utility transmission provider's OATT by reference must be consistent with or superior to this Final Rule.

[453] *See Illinois Commerce Commission,* 576 F.3d 470 at 476–77 (stating that ''[w]e do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars''). *See also MISO Transmission Owners,* 373 F.3d 1361 at 1369 (stating that ''we have never required a ratemaking agency to allocate costs with exacting precision''); *Sithe,* 285 F.3d 1 at 5.

[454] As discussed above, the Commission proposed to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of Public Policy Requirements established by state or federal laws or regulations that drive transmission needs. As discussed above, we adopt this requirement in this Final Rule.

[455] In addition, the Commission preliminarily found that this principle does not affect the cross-border cost allocation methods developed by PJM and MISO in response to Commission directives related to their intertwined configuration. *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, at P 10; *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084; *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,102. As noted above, we adopt this finding in this Final Rule.

[456] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164.

transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.[457]

(3) If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

(4) Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

(5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

(6) The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out and explained in detail in the compliance filing for this rule.

588. The Proposed Rule also states that public utility transmission providers will have the first opportunity to develop cost allocation methods for regional and interregional transmission facilities in consultation with stakeholders. In the event that no agreement can be reached, the Commission would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements.

b. Comments on Use of Principles-Based Approach

589. Many commenters generally support the use of cost allocation principles although this support is often expressed as part of general support for the Proposed Rule's six proposed cost allocation principles as a package.[458] For example, Dominion believes that by providing cost allocation principles linked to planning, the Commission has taken the correct approach without being overly prescriptive. Dayton Power and Light states that these principles help to reduce uncertainty and provide guidance to interested stakeholders. Energy Future Coalition Group states that the proposed principles follow the direction laid out by the court in the *Illinois Commerce Commission* case, and address legitimate concerns that have been raised by some opponents of broad cost allocation policy over the past two years. On the other hand, as discussed above,[459] some comments oppose any generic action on regional and interregional cost allocation and therefore do not support the use of cost allocation principles to support such action.

590. Almost all commenters urge the Commission not to adopt a ''one-size-fits-all'' approach to cost allocation and to retain regional and interregional flexibility.[460] For example, APPA and Transmission Agency of Northern California state that the Commission should not prescribe a uniform approach to interregional transmission cost allocation, and should allow for regional and interregional differences. Transmission Agency of Northern California states that this issue is being addressed at a level where local and regional differences can be addressed more fully, and that it supports the Proposed Rule's assumption that this ongoing process should not be disrupted by this rulemaking.

591. Several commenters ask the Commission to address the Proposed Rule's provision regarding ''in the event that no agreement can be reached.''[461] They contend that if the Commission adopts a rule providing that it would select a backstop cost allocation method in the event that stakeholders within a region cannot agree to a regional cost allocation method or if regions cannot agree on a cost allocation method for interregional projects, the Commission should provide additional guidance that would help stakeholders to reach agreement. For example, Multiparty Commenters request that the Commission clarify: The level of stakeholder agreement that is acceptable; what would be evidence of an impasse; whether the Commission will defer to the majority; and whether the Commission will extend the time in which to make compliance filings to afford more time to obtain an agreement. Similarly, for interregional cost allocation, Anbaric and PowerBridge recommend that the Commission stipulate a reasonable period of time for regions to reach agreement on a proposed interregional cost allocation method.

592. Some commenters recommend that the Commission adopt an interregional default cost allocation method if regions cannot agree to such a method themselves, although they note that specific projects will involve unique facts and circumstances. Anbaric and PowerBridge believe that, if regions cannot agree on an interregional cost allocation method, the Commission could impose an agreement based on the facts and circumstances of the project. Massachusetts Municipal and New Hampshire Electric state that, even if an interregional default method is implemented, whether by mutual agreement or by Commission directive, disputes will arise about the application of that method to a given set of facts. Massachusetts Municipal and New Hampshire Electric suggest that the Commission can address these concerns by adopting expedited hearing procedures to be applied in such cases.

593. Other commenters suggest a variation on or alternative to the idea that the Commission adopt a default cost allocation method for regional and interregional cost allocation if stakeholders or regions cannot come to a consensus themselves.[462] Wind Coalition states that having a default cost allocation method would allow construction to commence while an alternative cost allocation method is being developed, if needed. It states that this would be particularly needed for cross-border cost allocation because there are currently few interregional agreements on cost allocation. Wind Coalition also states that matching cost

[457] For example, a DC line that runs from a first transmission planning region, through a second transmission planning region, and into a third transmission planning region, with no tap in the second region, may not provide any benefits to the second region.

[458] *E.g.,* DC Energy; WIRES; Dominion; and Dayton Power and Light.

[459] *See* discussion *supra* section II.

[460] *E.g.,* Large Public Power Council; Kansas Corporation Commission; and Nebraska Public Power District.

[461] *E.g.,* Anbaric and PowerBridge; AWEA; MidAmerican; Multiparty Commenters; and Southern Companies.

[462] *E.g.,* American Transmission; AWEA; NextEra; and Wind Coalition.

allocation with a proactive regional or interregional plan is important for justifying regional cost sharing.

594. Some commenters argue that, if a region or regions fail to agree on a method, the Commission should not select a default cost allocation method and also should not select a cost allocation method based on the record here.[463] APPA contends that adoption of a default cost allocation method or particular cost allocation principles or guidelines would influence the prospects for successful regional and interregional negotiation because stakeholders that support the default method will be unwilling to negotiate, knowing that if no agreement is reached, their preferred method will be adopted as the default. PSEG Companies argue that adoption of a single default cost allocation method would be inconsistent with the Proposed Rule's ''beneficiary pays'' approach. PSEG Companies believe that the ''roughly commensurate'' standard that the *Illinois Commerce Commission* decision requires will be satisfied only by happenstance under a default cost allocation method. PSEG Companies also disagree with comments by National Grid, AEP, and others that the Commission should institute a default cost allocation method for transmission planning regions that would apply regardless of the nature of the facilities planned (*i.e.,* reliability or economic). PSEG Companies suggest that the Commission clarify how interregional cost allocation will be handled in the absence of an interregional agreement, and it should make clear that the existence of such an agreement is a prerequisite to the assignment of costs to another transmission planning region and its customers. PSEG Companies also state that, if certain regions decline to enter into interregional agreements, the Commission should adopt a ''do not harm'' standard applicable to such regions as a corollary principle, that is, no region may plan its system in a way that would impose costs on other regions.

595. Some commenters suggest a particular default method that the Commission should adopt if it decides to have a default cost allocation method, such as the SPP highway/byway mechanism.[464] However, other commenters express concern with establishing a ''one-size-fits-all'' default allocation method.[465] In particular, New England States Committee on Electricity and Identified New England Transmission Owners urge the Commission to reject recommendations to adopt the highway/byway mechanism as a default cost allocation method, instead asking the Commission to respect regional differences. Sunflower and Mid-Kansas submit that the Final Rule should provide for two-third regional (or interregional) allocation of costs and one-third to the ultimate sink zone for all network upgrades approved through an interregional plan that are needed for variable energy resource integration.

596. With respect to the question of whether the Commission should establish an interim cost allocation method until stakeholders have time to reach consensus, AWEA states that the current market structure and the mechanisms used to allocate costs between transmission providers outside organized market regions needs to mature further before transmission providers in many of these market regions will be able to fully comply with the Proposed Rule. It states that if transmission providers outside organized market regions cannot demonstrate a binding cost allocation method as envisioned by the Proposed Rule, it would be appropriate for the Commission to consider an interim method to address cost allocation in those regions, such as using an ''intertie open season'' to create a record about the appropriate allocation of costs.

597. NextEra suggests that, for non-RTO regions, regional cost recovery should be promoted by an adder on the transmission rates of public utility transmission providers (and extended to non-jurisdictional utilities via reciprocity). Southern Companies respond that this approach is not feasible because it does not address the fact that their OATT recovers only the share of the cost attributable to their provision of wholesale transmission service. Southern Companies state that even with an adder, third parties would be limited to recovering approximately 15 percent of their transmission costs, which is comparable to Southern Companies' cost recovery.

598. Massachusetts Departments and MidAmerican state that the Commission should narrowly apply any authority it has to develop a cost allocation method only for specific projects rather than requiring an established mechanism for all projects. For instance, MidAmerican proposes that the Commission adopt a default cost allocation method that would be used only if the stakeholders fail to agree regarding a 500 kV or higher alternative current facility (except high voltage direct current projects) that is identified by the planning process as providing widespread benefits. In this limited case, MidAmerican suggests that the Commission adopt a streamlined dispute resolution mechanism with a rebuttable presumption in favor of specified regional and interregional cost allocation methods. MidAmerican states that the record in the proceeding before the Commission on remand from the Seventh Circuit *Illinois Commerce Commission* opinion, demonstrates the reliability, economic, and societal benefits of 500 kV and above transmission, and it also documents that these benefits are realized regionwide whenever extra-high voltage transmission is deployed.

599. Wisconsin Electric states that it may be useful to consider the extent to which statewide stakeholder collaboratives could be effective in helping to resolve interstate cost allocation and cost recovery controversies. It points to California's Renewable Energy Transmission Initiative, which distinguishes stakeholders who are willing to work in good faith to resolve a project from those who only oppose transmission for self-interested reasons. Northwestern Corporation (Montana) is concerned that the proposal could have uneconomic consequences in that a high-cost allocation solution could be involuntarily allocated to an unwilling entity that has a lower-cost solution. Northern Tier Transmission Group is also worried about the difficulties that would arise in the context of allocating costs to entities that are unwilling to incur them.

600. Some commenters state that the Commission should not close the door on existing or evolving processes.[466] Salt River Project states that requiring involuntary cost sharing would risk foreclosure of promising alternatives and superior options for reliable and least-cost service for customers. Salt River Project is also concerned that arbitrary solutions could result that fail to honor local and regional interests.

[463] *E.g.,* APPA and PSEG Companies.

[464] Several commenters suggested this method including AWEA, Multiparty Commenters, and NextEra.

[465] *E.g.,* Connecticut & Rhode Island Commissions; Kansas Corporation Commission; Salt River Project; WIRES; and Wisconsin Electric.

[466] In addition, WIRES also notes that a default method where regional parties reach an impasse may look more attractive if the Commission's principles provide only generalized guidance. However, WIRES states that greater reliance on principled, up-front guidance for allocating the costs of transmission can provide a high degree of reassurance to parties engaged in negotiating a method. It states that only the Commission can provide this level of certainty.

601. Dominion states that it is unlikely any imposed allocation method will generate uniform agreement or consensus so if competing principled approaches are proposed, the Commission should not make a ruling in favor of one over the other, but consider whether a blended approach could result in a just and reasonable solution. Southern Companies state that the policies of promoting the expansion of the transmission grid would be better served by developing a set of reasonable cost allocation principles that would be used to develop a cost allocation method only when an actual, multi-jurisdictional project is pursued. With respect to interregional cost allocation, New York Transmission Owners argue that it is neither necessary nor reasonable for the Commission to impose an interregional cost allocation method if one is not agreed to by the regions.

602. Further, other commenters tell us that principles alone are not enough, and propose alternative solutions. These comments are summarized and addressed below in the discussion of the proposed cost allocation principles.

c. Commission Determination

603. The Commission requires each public utility transmission provider to show on compliance that its cost allocation method or methods for regional cost allocation and its cost allocation method or methods for interregional cost allocation are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles. Commission determinations on each cost allocation principle are set out in the subsections below. The six regional cost allocation principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation. The six analogous interregional cost allocation principles apply to, and only to, a cost allocation method or methods for a new transmission facility that is located in two neighboring transmission planning regions and accounted for in the interregional transmission coordination procedure in an OATT. These cost allocation principles do not apply to other new transmission facilities and therefore do not foreclose the opportunity for a developer or individual customer to voluntarily assume the costs of a new transmission facility, as discussed further below in the Participant Funding subsection.

604. We adopt the use of cost allocation principles because we do not want to prescribe a uniform method of cost allocation for new regional and interregional transmission facilities for every transmission planning region. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, we retain regional flexibility and allow the public utility transmission providers in each transmission planning region, as well as pairs of transmission planning regions, to develop transmission cost allocation methods that best suit the needs of each transmission planning region or pair of transmission planning regions, so long as those approaches comply with the regional and interregional cost allocation principles of this Final Rule.

605. The Commission recognizes that a variety of methods for cost allocation may satisfy a set of general principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[467] Similarly, other methods that would allocate costs to a narrower class of beneficiaries may be appropriate, provided that the methods reflect an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region or pairs of transmission planning regions.

606. In response to comments that request further detail from the Commission on what an appropriate cost allocation method would look like, we conclude that public utility transmission providers in each transmission planning region or pair of transmission planning regions must be allowed the opportunity to determine for themselves the cost allocation method or methods to adopt based on their own regional needs and characteristics, consistent with the six cost allocation principles. With the exception of the limitation on participant funding explained below, we decline to prejudge any particular method or set of methods generically in this Final Rule.

607. In the event of a failure to reach an agreement on a cost allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements. Public utility transmission providers must document in their compliance filings the steps they have taken to reach consensus on a cost allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view as necessary for the Commission to make a determination of the appropriate cost allocation method or methods. Each public utility transmission provider must make an individual compliance filing that includes its own proposed method or set of methods of allocating costs and explains how it believes its method or methods satisfy the cost allocation principles and is appropriate for its transmission planning region or pair of transmission planning regions. Groups of public utility transmission providers that agree on a proposed method or methods may make a coordinated filing or filings with their common views. The public utility transmission providers in each transmission planning region or pair of transmission planning regions will have the burden of demonstrating that sufficient effort has been made to comply with the requirements of this Final Rule.

608. Interested parties will be provided an opportunity to comment on these compliance filings, thereby creating a record on which the Commission could develop an appropriate cost allocation method or methods, or establish further procedures to do so. We do not impose other specific filing requirements for what the record should contain. As with any other proceeding before the Commission, should more information become necessary during the Commission's review process, the Commission may request more information from the parties at that time.

609. The Commission will consider in response to compliance filings all issues raised by commenters, such as what constitutes an impasse, whether there should be deference to the majority, and whether granting additional time for the region to continue negotiations would be appropriate. The procedural mechanisms used by the Commission in response to compliance filing(s) will depend on the nature of remaining

[467] We address comments below suggesting that the cost allocation principles be applied to require regional cost sharing for all transmission facilities at 345 kV or higher.

disputes and what issues are still at stake that are preventing the public utility transmission providers in each transmission planning region or pair of transmission planning regions from reaching a consensus. The Commission will not prejudge the outcome of the dispute by stating at this time whether there should be deference to the views of any particular segment of stakeholders, as suggested by Multiparty Commenters.

610. We decline to adopt a default regional or interregional cost allocation method in this Final Rule. We decline to do so for reasons similar to the reasons we declined to impose a uniform cost allocation method for all transmission planning regions. Many factors may make it appropriate for different transmission planning regions to have different cost allocation methods. It thus would not be practical or reasonable for the Commission to establish such default methods. We agree with APPA and others that having a known default method would cause those who favor it not to negotiate in good faith for an alternative cost allocation method. For these same reasons, we will not establish an interim cost allocation method that applies between the time of the issuance of this Final Rule and the time when stakeholders reach a consensus.

611. The twelve regional and interregional proposed cost allocation principles are discussed below in pairs of six separate subsections. Because the proposed cost allocation principles for regional transmission facilities are very similar to the proposed cost allocation principles for interregional transmission facilities, almost all commenters discussed them together as if they were a single principle. Therefore, the Commission discusses the corresponding sets of cost allocation principles together and, except where otherwise indicated, the Commission determinations regarding each set of cost allocation principles apply to both the regional and interregional transmission facilities in a regional transmission plan for purposes of cost allocation. The cost allocation principles in the Final Rule apply only to those new transmission facilities selected in a regional transmission plan for purposes of cost allocation and new transmission facilities subject to the cost allocation provision of the interregional coordination procedures in an OATT.

2. Cost Allocation Principle 1—Costs Allocated in a Way That is Roughly Commensurate With Benefits [468]

a. Comments

612. Many commenters generally support the Commission's first proposed cost allocation principle for both regional and interregional cost allocation, which provides that the costs of transmission facilities must be allocated to those that benefit in a manner at least roughly commensurate with the estimated benefits received.[469] For example, Transmission Access Policy Study Group states that the roughly commensurate standard appears to be consistent with the *Illinois Commerce Commission* decision and cost causation principles. Additionally, Westar states that transmission customers in a region should not pay for transmission projects that do not provide commensurate benefits and that only transmission projects that have been thoroughly reviewed in the regional process, show a benefit to the region and are approved by the transmission provider should be included in regional rates. Commenters also generally support the Proposed Rule's proposal to adhere to cost causation principles and also support a ''beneficiaries pay'' approach.[470] Dayton Power & Light comments that ''beneficiaries pay'' is the touchstone principle for cost allocation. American Forest & Paper argues that such an approach provides for better incentives for analysis of costs and alternatives.

613. Several commenters, however, support a broader definition of benefits and beneficiaries.[471] NextEra argues that the Final Rule should mandate that planning processes consider various types of benefits, rather than leaving it to a transmission provider's discretion. Old Dominion asserts that adopting a narrow approach to assessing benefits for cost allocation purposes would ignore the broader benefits associated with maintaining and expanding the regional high voltage transmission system—such as more options when making resources decisions in regional markets. Old Dominion notes that restricting the cost causation benefits to a snapshot in time would be problematic for dynamic high voltage regional transmission facilities. National Grid supports a cost allocation method that takes into account both the quantitative and qualitative benefits of transmission. Xcel suggests that the Commission permit methods, such as SPP's highway/byway approach, which broadly allocate costs based on general determination of the benefits provided to a region and stakeholders. AWEA and Multiparty Commenters state that it does not make sense to use cost allocation mechanisms that look only at public policy requirements established by existing state or federal laws or regulations because transmission assets are used for 40 years or longer, and they encourage the Commission to clarify that the appropriate cost allocation mechanisms should take into account the benefits of transmission in addressing likely future public policy requirements as well as existing ones. American Antitrust Institute recommends that the pro-competitive benefits of transmission be recognized.

614. PUC of Ohio recommends that the definition of beneficiary also should include those who gain from the ability to place electricity onto the grid. It states that load should not be solely burdened with the costs of the transmission grid; generation should be responsible for its fair share of the costs. Maine Parties agree, characterizing a beneficiary pays as more consistent with cost causation principles than a cost socialization method.

615. In response to comments supporting a broader definition of benefits, Powerex states that it disagrees that the Proposed Rule is intended to allow for allocation methods that could impose cross-subsidization and states that cost allocation methods for jurisdictional facilities must adhere to cost causation principles. Powerex argues that state or federal public policy requirements do not constitute evidence of a general or undifferentiated benefit to all market participants. Thus, Powerex argues, the Final Rule should emphasize that cost causation principles are and will remain the foundation of all acceptable cost allocation methods and make clear that the Commission rejects cost allocation proposals or outcomes that depart from this principle by promoting cross-subsidization.

616. PSEG Companies take issue with the Proposed Rule's suggestion that the determination of who constitutes a beneficiary may be based on an assessment of ''likely future scenarios,''

[468] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[469] *E.g.,* Bay Area Municipal Transmission Group; Santa Clara; Consolidated Edison and Orange & Rockland; Transmission Access Policy Study Group; United States Senators Dorgan and Reid; Professor Ignacio Perez-Arriaga; New York ISO; New York PSC; New York Transmission Owners; Westar; City and County of San Francisco; Conservation Law Foundation; Energy Future Coalition Group; Solar Energy Industries; and EarthJustice.

[470] *E.g.,* Dayton Power & Light; Conservation Law Foundation; and American Forest & Paper.

[471] *E.g.,* NextEra; AWEA; EarthJustice; and Atlantic Grid.

arguing that regional planners should not be prognosticators and that the more ''scenarios'' that are introduced, the more inexact and speculative their proposed plans and cost allocation determinations will become.

617. Dayton Power & Light seeks clarification of what it considers an ambiguity in regional and interregional Principle 1, which allows a regional transmission planning process to consider the extent to which facilities ''in the aggregate'' provide benefits.[472] Dayton Power & Light states that this language could be taken to mean that if the existing network benefits a utility, then that is a benefit that justifies the utility allocating to it the incremental costs created by a new transmission project located far away, even if the project did not provide incremental benefits. According to Dayton Power & Light, this result would be inconsistent with *Illinois Commerce Commission* decision.

618. Some commenters also request that the proposed principle be expanded so that the costs of transmission facilities are allocated to those within the planning region and adjacent planning regions that benefit from those facilities.

619. Some commenters request clarification regarding what constitutes ''benefits'' to be considered in any cost allocation method.[473] Alabama PSC states that the cost allocation proposals are too vague and potentially overbroad, and it requests that the Commission make clear that costs cannot be recovered from retail customers. WIRES requests that the Commission articulate more clearly the definitions, presumptions, and methods associated with the beneficiary pays approach.

620. A number of commenters differ on what constitutes ''benefits'' and who constitutes ''beneficiaries.'' Several commenters state concern that the definition of ''benefits'' could be interpreted too broadly, particularly with respect to transmission projects driven by public policy goals.[474] Atlantic Wind Connection requests clarification as to how the costs associated with public policy initiatives would be fairly assigned to beneficiaries, so that a results-oriented action plan emerges from the process. Transmission Access Policy Study Group argues that benefits are difficult to quantify and cautions the Commission against including generalized social or environmental benefits in cost allocation calculations. Transmission Access Policy Study Group and Colorado Independent Energy Association argue that production cost savings by itself is not sufficient to identify the universe of beneficiaries.[475] Transmission Access Policy Study Group argues, however, that the Commission should clarify that it will not accept cost allocation methods that assign costs regionally based on a presumption of some general, unquantified regional benefits or vague assertions of possible future benefits.

621. Some commenters raise similar concerns about the difficulty of quantifying benefits, and they suggest that benefits resulting in allocation of costs be direct, clear, and identifiable.[476] Other commenters also believe it is important to make sure cost allocation mechanisms do not favor long-line transmission development or artificially depress the value of local renewable resources.[477] In its reply comments, Ohio Consumers' Council agree that benefits should not be defined too broadly and recommends that the Commission strictly adhere to cost causation principles in implementing the Final Rule. Further, Ohio Consumers' Council suggests that the Commission uphold cost causation principles by requiring substantial evidentiary showings of benefits and costs prior to approving the imposition of regional or interregional transmission costs on consumers. With respect to interregional cost allocation, North Carolina Agencies contend that if the Commission assumes benefits too broadly, a public utility's retail customers may bear a share of costs based on the policy objectives of other states. Alabama PSC shares this concern. According to Western Area Power Administration, only the direct beneficiaries of a project, *i.e.,* beneficiaries that make direct use of the facilities, should be counted as ''beneficiaries,'' and to the extent that costs are allocated to such beneficiaries, only the costs associated with the least-cost method of achieving the benefits should be allocated. LS Power states that it is important for the Final Rule to acknowledge that the factors that drive transmission planning do not fully define the range of beneficiaries.

b. Commission Determination

622. The Commission adopts the following Cost Allocation Principle 1 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 1: The cost 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. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[478]

and

Interregional Cost Allocation Principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[479]

623. As discussed above,[480] requiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts. As the Commission stated in Order No. 890, the one factor that it weighs when considering a dispute over cost allocation is whether a proposal

[472] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 164, 174.

[473] *E.g.,* California Municipal Utilities; Northern Tier Transmission Group; Omaha Public Power District; Gaelectric; and Atlantic Grid.

[474] *E.g.,* Florida PSC; Public Power Council; Transmission Dependent Utility Systems; and Coalition for Fair Transmission Policy.

[475] *E.g.,* Transmission Access Policy Study Group; and Colorado Independent Energy Association.

[476] *E.g.,* East Texas Cooperatives and G&T Cooperatives.

[477] *E.g.,* New England States Committee on Electricity; Nebraska Public Power District; Sacramento Municipal Utility District; California State Water Project; and Northeast Utilities.

[478] In the Proposed Rule, Regional Cost Allocation Principle 1 referred to ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs.'' As defined in P 0 of this Final Rule, we use ''Public Policy Requirements'' in Regional Cost Allocation Principle 1 and throughout our discussion of the Cost Allocation Principles.

[479] We note that the phrase ''individually or in the aggregate'' is not contained in Interregional Cost Allocation Principle 1 because interregional transmission facilities are considered facility by facility by pairs of transmission planning regions, unless pairs of transmission planning regions choose to do otherwise.

[480] *See* discussion *supra* P 0 and section V.B.

fairly assigns costs among those who cause the costs to be incurred and those who otherwise benefit from them.[481] Therefore, it is appropriate here to adopt a cost allocation principle that includes as beneficiaries those that cause costs to be incurred or that benefit from a new transmission facility.

624. However, the Commission is not prescribing a particular definition of ''benefits'' or ''beneficiaries'' in this Final Rule. In our view, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Moreover, allowing the flexibility to accommodate a variety of approaches can better advance the goals of this rulemaking. The cost allocation principles are not intended to prescribe a uniform approach, but rather each public utility transmission provider should have the opportunity to first develop its own method or methods. Also, we recognize that regional differences may warrant distinctions in cost allocation methods.

625. While some commenters express concerns that the definition of benefits could be interpreted too broadly or too narrowly, we do not believe that further defining ''benefits'' in this Final Rule is a necessary or appropriate means to ensure that this will not be the case. We expect that concerns regarding overly narrow or broad interpretation of benefits will be addressed in the first instance during the process of public utility transmission providers consulting with their stakeholders. If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact. This point applies equally to the comments that note the potential difficulties in quantifying benefits. We note in response to Transmission Access Policy Study Group, that any benefit used by public utility transmission providers in a regional cost allocation method or methods must be an identifiable benefit and that the transmission facility cost allocated must be roughly commensurate with that benefit. Western Area Power Administration takes the position that beneficiaries should be limited to those that it describes as making direct use of the transmission facilities in question, but this fails to acknowledge that other benefits may accrue to an interconnected transmission grid.

[481] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

626. We agree with Powerex that a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method. In response to PSEG Companies, we disagree that basing a determination of who constitutes a ''beneficiary'' on ''likely future scenarios'' necessarily would result in inexact and speculative proposed transmission plans and cost allocation methods. Scenario analysis is a common feature of electric power system planning, and we believe that public utility transmission providers are in the best position to apply it in a way that achieves appropriate results in their respective transmission planning regions.

627. In response to Dayton Power & Light, the provisions of Regional Cost Allocation Principle 1 regarding determination of the beneficiaries of transmission facilities ''individually or in the aggregate'' refer only to cost allocation for new transmission facilities. The public utility transmission providers in a transmission planning region may propose a cost allocation method that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. We did not intend this language to be a finding that the benefits of existing transmission facilities in and of itself may justify cost sharing for new transmission facilities. We are not ruling on that matter in this Final Rule.

628. We also decline to expand, as requested by some commenters, the scope of beneficiaries for new transmission facilities such that costs may be involuntarily allocated to those within an adjacent planning region that benefit from those facilities. As discussed in adopting Cost Allocation Principle 4 below, the allocation of the cost of a transmission facility that is located entirely within one transmission planning region may not be subject to a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries.[482]

629. Finally, if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.

[482] *See* discussion *infra* section IV.E.5.

3. Cost Allocation Principle 2—No Involuntary Allocation of Costs to Non-Beneficiaries [483]

a. Comments

630. Most of the commenters that addressed proposed Cost Allocation Principle 2 support it.[484] Ad Hoc Coalition of Southeastern Utilities and Nebraska Public Power District state that while the proposition in Cost Allocation Principle 2 might seem self supporting, they understand that there are those who would encourage the Commission to mandate regional or even interconnectionwide cost sharing, but the Commission's decision to decline to do so is sensible.

631. Some commenters who express general support also express some concerns. For example, MISO Transmission Owners urge the Commission to ensure that this principle does not contribute to free rider problems.

632. Some commenters are concerned that the principle could be interpreted too narrowly or too broadly. For instance, NextEra asks that the Commission construe the ''no benefit'' standard narrowly by providing that there is a benefit if a customer receives any benefit from the transmission facility, including an economic, reliability, or public policy benefit, particularly at or above certain voltage levels, over a reasonable period of time.

633. Some commenters do not support the principle and raise concerns that the ''no benefits'' language in the principle will rarely, if ever, be applicable to any transmission customer.[485] East Texas Cooperatives argue that by protecting only those that receive no discernible benefit, this principle conflicts with court precedent stating that the Commission cannot approve a pricing scheme that requires utilities to pay for facilities from which its members derive only trivial benefits. East Texas Cooperatives states that Principle 2 does not go far enough, and the Commission should clarify that only those customers who are reasonably expected to receive non-trivial benefits can be allocated costs. Other

[483] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[484] *E.g.,* Ad Hoc Coalition of Southeastern Utilities; Nebraska Public Power District; Connecticut & Rhode Island Commissions; New England States Committee on Electricity; New York ISO; and New York PSC.

[485] *E.g.,* Transmission Dependent Utility Systems and East Texas Cooperatives.

commenters, such as E.ON and Public Power Council, are worried that there will be stranded costs if a planning process exaggerates the benefits resulting from a particular project. Public Power Council believes the Commission should permit cost allocations that mitigate the risk of stranded costs and give due consideration to the impact on ratepayers prior to allocating costs.

634. On the other hand, Xcel is concerned that the principle, taken at face value, gives parties the ability to ''opt out'' of cost allocation arising from specific projects even as it offers parties the opportunity to participate fully in the planning process. Xcel maintains that the Order No. 890 transmission planning process and the linkage between transmission planning and cost allocation render moot any participant's argument that it receives no benefit. Xcel argues that the Order No. 890 planning principles are designed to result in the best projects to meet the needs of the planning region, and therefore it is unlikely that participants in the planning process would produce a plan with a project or set of projects that do not provide benefits to stakeholders.

635. Alliant Energy asks whether the Commission intended that membership in an ISO or RTO eliminates the prohibition of cost allocation for transmission projects to those entities that do not benefit. Alliant Energy does not believe this was the Commission's intent, but is seeks clarification to confirm its view.

636. Alliant Energy also seeks clarification of the term ''transmission facilities'' within the context of this principle. It asks whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, or something in between. Alliant Energy believes that such evaluations should be done on a holistic basis, noting that some individual projects will benefit certain entities more than others but that the evaluation of benefits and costs within the context of a cost allocation determination could reasonably include the cumulative impact of a collection of projects.

b. Commission Determination

637. The Commission adopts the following Cost Allocation Principle 2 for both regional and interregional cost allocation:

Regional Cost Allocation 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.[486]

and

Interregional Cost Allocation Principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.

The principle expresses a central tenet of cost causation and is thus essential to proper cost allocation.

638. In response to MISO Transmission Owners that Principle 2 might contribute to free rider problems, we agree that it, like all the other principles adopted in this Final Rule, requires careful consideration and application to ensure that they are implemented appropriately in practice. In response to NextEra, we decline to establish a threshold voltage level to define which benefits would be ineligible for cost allocation in this Final Rule.

639. East Texas Cooperatives is concerned that the Commission is protecting only those that receive no benefits but not those who derive only trivial benefits. It cites the Seventh Circuit's statement in *Illinois Commerce Commission* that emphasized that the Commission is not authorized to approve cost allocation methods that require entities that receive no benefits or benefits that are trivial in relation to the costs to be borne. We note that the court used the term ''trivial'' in a relative sense, *i.e.,* benefits that are trivial in relation to the costs assigned. This is implied in the concept of cost causation, and we therefore see no reason to amend the Principle 2 to include reference to it. Principle 1 requires that costs be allocated in a way that is roughly commensurate with the benefits received. This precludes an allocation where the benefits received are trivial in relation to the costs to be borne. Any beneficiaries that believe that the application of the cost allocation method or methods would assign to them costs for benefits, which are trivial, in relation to those costs is free to make a FPA section 205 or 206 filing.

640. We also require that every cost allocation method or methods provide for allocation of the entire prudently incurred cost of a transmission project to prevent stranded costs. We disagree with Xcel that the Principle 2 gives parties the ability to opt out of a Commission-approved cost allocation for a specific transmission project if they merely assert that they receive no benefits from it. Whether an entity is identified as a beneficiary that must be allocated costs of a new transmission facility is not determined by the entity itself but rather through the applicable, Commission-approved transmission planning processes and cost allocation methods. Permitting each entity to opt out would not minimize the regional free rider problem that we seek to minimize in this Final Rule.

641. With respect to Alliant Energy's request for clarification regarding RTO or ISO membership, we clarify that all the cost allocation principles, including Cost Allocation Principle 2 apply the allocation of costs to all new transmission facilities selected in the regional transmission plan for purposes of cost allocation, including RTO and ISO regions. In response to Alliant Energy's request to clarify whether the Commission intended that the principle be applied on a project-by-project basis, within the context of the entire regional transmission plan, we reiterate that the public utility transmission providers in a transmission planning region may propose a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, although they are not required to do so. To the extent they propose a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, and adequately support their proposal, Cost Allocation Principle 2 would not require a showing that every individual transmission facility in the group of transmission facilities provides benefits to every beneficiary allocated a share of costs of that group of transmission facilities. However, it is required that the aggregate cost of these transmission facilities be allocated roughly commensurate with aggregate benefits.

4. Cost Allocation Principle 3—Benefit to Cost Threshold Ratio[487]

a. Comments

642. Many commenters support the Commission's proposed Cost Allocation Principle 3, finding it to be a reasonable approach that would result in the construction of new transmission

[486] We added the words ''any of'' to the Regional Cost Allocation Principle 2 stated in the Proposed Rule to be consistent with interregional cost allocation Principle 2. We also added ''transmission'' before ''facilities'' to clarify the term in this Regional Cost Allocation Principle 2 and throughout our discussion of the Cost Allocation Principles.

[487] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

projects.[488] For example, ITC Companies states that the Commission's recommended cost threshold ratio is a necessary specification to prevent measures such as the sliding cost benefit ratio employed by MISO, which can require up to a 3 to 1 benefit to cost ratio for large regional long term transmission projects and which has served to frustrate the construction of market efficiency projects. American Transmission believes that the Commission's proposal seems like a reasonable threshold that would likely result in projects actually being constructed.

643. Nonetheless, some commenters raise specific concerns. While generally supportive of the proposal, MISO Transmission Owners suggest that transmission providers and stakeholders in each planning region be permitted to develop a benefit to cost ratio that is appropriate for that region, provided that ratios are not set so high as to preclude any projects from being built. Similarly, MISO Transmission Owners argue that transmission providers and stakeholders should be permitted to develop appropriate criteria for defining benefits and costs. They also state that the Final Rule should indicate that any benefit to cost ratio for interregional transmission facilities should not supersede the ratio for a region's regional cost allocation. Transmission Dependent Utility Systems support this principle as a general concept, but they argue that it should be modified to ensure that the implementation of any cost benefit analysis is transparent to customers.

644. Several commenters oppose the use of a fixed benefit-cost threshold ratio.[489] A number of them stress the difficulties in quantifying benefits.[490] Some commenters argue that the Commission should focus on regional circumstances.[491] Northern Tier Transmission Group suggests that the Commission's focus should be on defining the types of benefits to be measured and how to measure them, rather than establishing a set threshold. Massachusetts Departments are concerned that a failure to reflect the full menu of benefits that could be realized by a proposed project could distort the balance between costs and benefits, and could preclude some beneficial projects at the planning stage that would have otherwise been approved. NextEra requests that benefits for this assessment should cover only economic benefits identified with the project, and not reliability or public policy benefits, as those benefits cannot be quantified in a similar manner.

645. Some commenters would like the Commission to establish either a higher or a lower benefit-cost ratio threshold. New York PSC believes that the proposed threshold is extremely low and does not adequately account for uncertainty in cost estimates and potential cost overruns. Connecticut & Rhode Island Commissions and Massachusetts Departments agree. On the other hand, AWEA, Wisconsin Electric, and NextEra urge the Commission to lower the proposed threshold. AWEA argues that if the Commission adopts the proposed threshold, it should be applied as a ceiling to ensure fair treatment for projects that have broad benefits over time. MEAG Power responds to AWEA's argument for a lower threshold, arguing that AWEA's proposal would unfairly shift to customers all risks associated with project development.

b. Commission Determination

646. The Commission adopts the following Cost Allocation Principle 3 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation,[492] it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.

and

Interregional Cost Allocation Principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation.[493] The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.

647. Cost Allocation Principle 3 does not require the use of a benefit to cost ratio threshold. However, if a transmission planning region chooses to have such a threshold, the principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan. Further, it allows public utility providers in a transmission planning region to use a lower ratio without a separate showing and to use a higher threshold if they justify it and the Commission approves a greater ratio.

648. Allowing for a transparent benefit to cost ratio may help certain transmission planning regions to determine which transmission facilities have sufficient net benefits to be selected in the regional transmission plan for purposes of cost allocation. For example, public utility transmission providers in a transmission planning region may want to use such a ratio to account for uncertainty in the calculation of benefits and costs. However, by requiring that a benefit to cost ratio, if adopted, not exceed 1.25 to 1 unless the public utility transmission providers in a transmission planning region justify, and the Commission approves, a greater ratio, will ensure that the ratio is not so high that transmission facilities with significant positive net benefits that would otherwise be selected in the regional transmission plan for purposes of cost allocation are not excluded from the regional transmission plan for purposes of cost allocation despite a positive ratio. The Commission therefore rejects requests to adopt a higher or lower threshold ratio, as advocated by some commenters.

649. In response to specific comments on this principle, the Commission agrees that a benefit to cost ratio should not be set so high as to preclude certain beneficial transmission projects from

[488] *E.g.,* ITC Companies; American Transmission; Omaha Public Power District; PSEG Companies; and Six Cities.

[489] *E.g.,* Northeast Utilities; Connecticut & Rhode Island Commissions; and Michigan Citizens Against Rate Excess.

[490] *E.g.,* Xcel and Northern Tier Transmission Group.

[491] *E.g.,* Michigan Citizens Against Rate Excess; Xcel; and Massachusetts Departments.

[492] To ensure consistency in the use of terms in this Final Rule, Cost Allocation Principle 3 as stated in the Proposed Rule has been changed to refer to facilities ''selected'' in a regional transmission plan, ability of a ''public utility transmission provider in a transmission planning region'' to use a benefit to cost threshold, and potential Commission approval of a ''higher'' ratio.

[493] The phrase ''net benefits to qualify for interregional cost allocation'' differs from the language in regional cost allocation Principle 3 because there is no plan at the interregional level for which projects would be selected. The word ''large'' was changed to ''high'' to be consistent with the language in regional cost allocation Principle 3.

being constructed. As such, the Commission finds (and several commenters agree) that a benefit to cost ratio of 1.25 to 1 to be a reasonable ratio that will not act as a barrier to the development and construction of valuable new transmission projects. Furthermore, regarding comments requesting that the Commission decline to establish a benefit to cost threshold given the difficulty in quantifying benefits, we reiterate that the benefit to cost ratio threshold identified in this Final Rule applies only if the public utility transmission providers of a transmission planning region choose to use a benefit to cost ratio to determine which transmission facilities are selected in the regional transmission plan for purposes of cost allocation. They may decide to have no benefit to cost ratio threshold greater than one at all.

650. Furthermore, in response to MISO Transmission Owners, if the issue of whether any benefit to cost ratio threshold for an interregional transmission facility may supersede the ratio for a transmission planning region's regional transmission cost allocation should be presented to us on compliance, we will address it then based on the specific facts in that filing.

5. Cost Allocation Principle 4—Allocation to be Solely Within Transmission Planning Region(s) Unless Those Outside Voluntarily Assume Costs [494]

a. Comments

651. Nearly all entities that commented on proposed Cost Allocation Principle 4 support it.[495] For example, NEPOOL states that it particularly supports Principle 4, citing New England's successful history of voluntarily planning, developing and allocating the costs of interregional projects with its neighbors. New York ISO agrees, stating that it would be appropriate to allow more expansive voluntary cost allocation arrangements, but would be premature and unrealistic to require all regions to adopt specific cost allocation methodologies on an *ex ante* basis that would be applicable to future situations as yet unknown.

652. However, some commenters raise specific concerns. East Texas Cooperatives argue that the restriction on the involuntary allocation of costs on an interregional basis should not be interpreted to prevent a transmission provider from proposing methods to capture the costs associated with the benefits enjoyed by exported energy. MISO Transmission Owners agree with this argument. The New England States Committee on Electricity states that interregional Principle 4 aligns with its view that any allocation method must not transfer costs to New England ratepayers to support development of facilities outside New England unless New England concludes that development of such facilities are the most cost-effective. Northeast Utilities states that it supports the principle in so far as it limits the allocation of costs for interregional projects only to facilities located within neighboring regions.

653. Other commenters argue that the Commission should not limit the application of interregional cost allocation requirements to interregional projects, suggesting that transmission facilities located solely within one region may have benefits in other regions.[496] NextEra recommends modifying Principle 4 so that if transmission facilities within one region clearly benefit another region, the Commission would allow cost recovery by the transmission providers in the region providing the benefits to the other. NextEra maintains that without such a mechanism, the benefitting region would receive a windfall. According to PJM, basing the cost allocation on physical location rather than analyzing power flows, reduced congestion, or improved reliability, is untenable, would invite gaming of the routing and siting process to drive particular cost allocation results, would make negotiations on cost allocation among neighbors more difficult, is inconsistent with a beneficiary pays approach, and is contrary to the existing PJM–MISO interregional cost allocation method. As an alternative, PJM suggests providing for the cost allocation of transmission to all system users that benefit from the increased transfer capability that the new facility provides, thereby moving the decision from controversies surrounding particular generation sources to the future characteristics of the transmission system, which is a subject that is more clearly within the Commission's authority and expertise.

654. Similarly, MISO seeks clarification that two or more regions may mutually designate transmission facilities located entirely within a single region as an interregional transmission facility and allocate costs accordingly, which is the approach taken in the current cross-border cost sharing arrangement between MISO and PJM. MISO, along with MISO Transmission Owners, argues that projects located entirely in one region may provide benefits to entities in the neighboring region.

655. Large Public Power Council states that its members cannot at this time commit to entering into interregional agreements regarding cost allocation. It notes that its members are creatures of state and municipal governments, and their authority to enter into binding arrangements is restricted.

656. Finally, the Coalition for Fair Transmission Policy sees an ambiguity in the Proposed Rule. It states that the Proposed Rule allows for costs to be allocated to a beneficiary even when the beneficiary has not entered into a voluntary arrangement to pay those costs, but proposed Cost Allocation Principle 4 states that costs cannot be allocated to an entity or region outside of the geographic boundaries of the planning region where the project is being constructed, absent a voluntary agreement.

b. Commission Determination

657. The Commission adopts the following Cost Allocation Principle 4 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan [497] 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. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.[498]

and

> Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the

[494] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[495] *E.g.,* ISO New England; Nebraska Public Power District; NEPOOL; New York ISO; New York PSC; Northern California Power Agency; and New York Transmission Owners.

[496] *See, e.g.,* NextEra; MISO; and MISO Transmission Owners.

[497] The phrase ''an intraregional facility'' was replaced with ''a transmission facility selected in a regional transmission plan'' to be consisted with P 0–0 n this Final Rule.

[498] At the end of the sentence, ''entities'' has been changed to ''beneficiaries'' to be precise. Slight wording changes have been made to the last sentence in this regional cost allocation Principle 4 and interregional cost allocation Principle 4 to clarify the point being made.

transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located.[499] However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.[500]

658. Regarding the allocation of the cost of a transmission facility that is located entirely within one transmission planning region and that is intended to export electric energy from that transmission planning region to another transmission planning region, the public utility transmission providers in the exporting transmission planning region may not have a regional cost allocation method or methods pursuant to this Final Rule that assigns some or all of the cost of that transmission facility to beneficiaries in another transmission planning region without reaching an agreement with those beneficiaries. The public utility transmission providers in such transmission planning regions may, however, negotiate an agreement to share the transmission facility's costs with the beneficiaries in another transmission planning region, as they always have been free to do. Doing so is not inconsistent with Regional Cost Allocation Principle 4.

659. Regarding the allocation of the cost of an interregional transmission facility that is located in two or more neighboring transmission planning regions and that is intended to export electric energy from one such transmission planning region to the other transmission planning region, this Final Rule requires that the public utility transmission providers in each pair of transmission planning regions have an interregional cost allocation method or methods for sharing the cost of such transmission facilities. However, Interregional Cost Allocation Principle 4 does not permit the cost allocation method or methods for those two transmission planning regions to assign the cost of the transmission facility to beneficiaries in a third transmission planning region except where the beneficiaries in the third transmission planning region voluntarily reach an agreement with the two transmission planning regions in which the transmission line is located. They also may satisfy the requirements of this Final Rule by having an interregional cost allocation method or methods for more than two transmission planning regions, although this Final Rule does not require them to do so.

660. We decline to adopt NextEra's recommendation that we modify Principle 4 to allow cost allocation by the public utility transmission providers in one transmission planning region to beneficiaries in another transmission planning region.[501] We acknowledge that this Final Rule's approach may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility. Nonetheless, the Commission finds this approach to be appropriate. For the reasons discussed herein, we are establishing a closer link between regional transmission planning and cost allocation, both of which involve the identification of beneficiaries. In light of that closer link, we find that allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. Indeed, if the Commission expected such participation, the resulting regional transmission planning processes would amount to interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner. The Commission is not requiring either interconnectionwide planning or interconnectionwide cost allocation.

661. MISO's and PJM's comments raise a similar issue that our proposed reforms inappropriately limit interregional cost allocation to those beneficiaries that are physically located in the transmission planning region in which the transmission facility is located. We find that this approach would raise the same concerns discussed immediately above.

662. We recognize that MISO and PJM have an existing cross-border cost allocation method that permits them, in certain cases, to allocate to one RTO the cost of a transmission facility that is located entirely within the other RTO, even if the facility does not cross the border between their two regions. Because MISO and PJM developed their cross-border allocation method in response to Commission directives related to MISO and PJM's intertwined configuration, we find that MISO and PJM are not required by this Final Rule to revise their existing cross-border allocation method in response to Cost Allocation Principle 4. If MISO and PJM believe their existing cross-border cost allocation method fulfills other principles discussed herein, they may explain that in the filings they make in compliance with this Final Rule.

663. In response to Large Public Power Council, as we discuss below,[502] a non-public utility transmission provider seeking to maintain a safe harbor tariff must ensure that the provisions of that tariff substantially conform, or are superior to, the *pro forma* OATT as it has been revised by this Final Rule. However, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.

664. We disagree with Coalition for Fair Transmission Policy's argument that there is an ambiguity in our reforms that allows for costs to be allocated to a beneficiary when the beneficiary has not entered into a voluntary arrangement to pay those costs, while also providing in Cost Allocation Principle 4 that the costs of transmission facilities in a regional transmission plan cannot be allocated to an entity in another transmission planning region, absent a voluntary agreement.

6. Cost Allocation Principle 5—Transparent Method for Determining Benefits and Identifying Beneficiaries[503]

a. Comments

665. Nearly all commenters that address this proposed principle supported it.[504] PSEG Companies agree

[499] The first two sentences of interregional cost allocation Principle 4 differ from regional cost allocation Principle 4 because at the interregional level, there may be a scenario where a transmission facility is located in one transmission planning region but provides benefits to another transmission planning region. For example, if regions A and B plan an interregional transmission facility that they believe benefits region C, regions A and B cannot allocate costs of that facility to region C involuntarily.

[500] "Transmission facility" was changed to "upgrade" in each instance in this sentence to make it consistent with the last sentence in regional cost allocation Principle 4. The end of the last sentence is revised to be consistent with Regional Cost Allocation Principle 4.

[501] *See* discussion *supra* section IV.D.

[502] *See* discussion *infra* section V.B.

[503] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[504] *E.g.,* SPP; Transmission Access Policy Study Group; and Transmission Dependent Utility Systems.

that there is a need for transparent cost allocation and that customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. Further, PSEG Companies state that it should be clear which customers are benefiting from and paying for system upgrades before they are built, as this will minimize after-the-fact debates and litigation.

666. Some commenters that support the principle caution that it will be difficult to determine costs and benefits with mathematical precision.[505] In light of such difficulties, Connecticut & Rhode Island Commissions suggest that transmission cost allocation methods be pragmatic. DC Energy raises concerns about the use of biased assessments, and it suggests that one method for improving the reliability of cost-benefit analyses is to require that only direct costs and benefits be considered in economic studies since they offer greater certainty. PSEG Companies agree with the proposed principle and suggest that for non-reliability projects, there should be a more definitive link between identified beneficiaries and the costs to be paid.

667. Several commenters raise specific issues with respect to the proposed principle. Transmission Dependent Utility Systems urge the Commission to recognize that transparency alone is insufficient without load serving entity involvement in the planning and development of the cost allocation method. Finally, MISO Transmission Owners argue that current RTO processes provide significant transparency.

b. Commission Determination

668. The Commission adopts the following Cost Allocation Principle 5 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

and

Interregional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility.[506]

669. Requiring cost allocation methods and their corresponding data requirements for determining benefits and beneficiaries to be open and transparent ensures that such methods are just and reasonable and not unduly discriminatory or preferential. Furthermore, greater stakeholder access to cost allocation information will help aid in the development and construction of new transmission, as stakeholders will be able to see clearly who is benefiting from, and subsequently who has to pay for, the transmission investment. In addition, the Commission agrees that such access to information may avoid contentious litigation or prolonged debate among stakeholders.

670. As the Commission stated in the Proposed Rule, we recognize that identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. However, the Commission finds that a transparent transmission planning process is the appropriate forum to address these issues, and by addressing these issues, there will be a greater likelihood that regions can build the new transmission facilities selected in the regional transmission plan for purposes of cost allocation.

671. We acknowledge the concerns that the method or methods for determining benefits and beneficiaries must balance being pragmatic and implementable with being accurate and unbiased. Cost Allocation Principle 5 requires that the method or methods be known and transparent. As stakeholders participate in the development of such methods, their input should ensure that the method or methods ultimately agreed upon is balanced and does not favor any particular entity. In developing this method or methods, public utility transmission providers and their stakeholders are also free to consider suggestions, such as those made by DC Energy, that only direct costs and benefits should be considered in economic studies. We will not, however, opine on such suggestions at this time. Rather, the Commission will review such matters once the cost allocation method or methods are filed on compliance.

672. In response to MISO Transmission Owners, the Commission declines at this time to rule on whether any current RTO and ISO processes provide enough transparency to satisfy Cost Allocation Principle 5. Such determinations will be made upon the submittal of a compliance filing by any RTO or ISO.

7. Cost Allocation Principle 6—Different Methods for Different Types of Facilities[507]

a. Comments

673. Many commenters generally support proposed Cost Allocation Principle 6, arguing that transmission projects are built for different purposes, such as for reliability or economic reasons, and different methods may therefore be appropriate.[508] Four G&T Cooperatives state that the planning regions should be given latitude to determine within reason the range of benefits that can be considered for cost allocation purposes, as well as the prioritization and relative value of such benefits. Pennsylvania PUC contends that cost allocation methods should maintain stable transmission rates that will be preferable both to the customers who pay the rates and the system planners who have to forecast future expenditures for the system. It argues that a cost allocation method should be flexible enough to accommodate different types of renewable energy from a diversity of sources, public policy changes, and potential shifts from older fossil fuel generation and development of other energy sources such as nuclear generation. Pennsylvania PUC also suggests that a cost allocation method be able to accommodate different types of facilities such as those serving renewable and non-renewable generators, both economic and reliability projects, as well as specialized projects such as generator interconnection facilities. MISO Transmission Owners agree and state that the applicable method should be determined through the stakeholder planning process. Dayton Power & Light states that one method may be appropriate, such as the beneficiary-pays approach, but the method by which beneficiaries are identified may depend on the type of project involved. New Jersey Board also supports flexibility and states that further analysis must be completed to

[505] *E.g.,* NextEra and Sunflower and Mid-Kansas.

[506] ''Interregional'' has been added before ''transmission facility'' at the end of the sentence to be precise.

[507] For the full text of this principle, *see* P 0 for regional cost allocation and P 0 for interregional cost allocation.

[508] *E.g.,* Indianapolis Power & Light; NEPOOL; Public Power Council; Northeast Utilities; New Jersey Board; E.ON; American Transmission; Dayton Power and Light; Delaware PSC; Dominion; New England States Committee on Electricity; and PSEG Companies.

determine how best to allocate costs for transmission driven primarily by public policy requirements because the beneficiaries may differ markedly from the beneficiaries of transmission facilities built for reliability purposes.

674. PSEG Companies request that reliability and non-reliability projects be treated differently for cost allocation purposes, and they advocate adopting a voting mechanism for economic projects that would require that proposed economic upgrades be voted on by the entities that have been deemed to benefit from them and who in turn would be responsible for paying for them. National Grid, however, is concerned about the use of supermajority voting requirements for economic transmission projects. In response, Con Edison points favorably to New York ISO's supermajority voting requirements for economic transmission projects in its transmission planning process.

675. In its reply comments, PJM proposes a possible way to reconcile what it views as competing directives in the Proposed Rule regarding transmission planning and cost allocation related to economic, reliability, and public policy projects. Economic and reliability projects would be included in one category, under which a beneficiary pays approach would match the planning purposes used (*e.g.,* avoiding a violation of a reliability standard). Public policy projects would comprise the second category, under which the Commission would align the planning and cost allocation for such projects with regional action taken by states sharing similar public policy objectives. PJM suggests that regions could form interstate compacts to identify shared public policy goals and resource requirements and accept the allocation of costs associated with those projects. PJM further suggests a ''safe harbor'' to prevent states from having to absorb costs for public policy projects undertaken in other states.

676. Large Public Power Council believes that the interregional allocation of costs is a topic on which consensus is feasible only in the context of specific projects proposed by project developers to satisfy identified market needs.

677. Some commenters point to existing approaches as being adequate to meet this principle. Northeast Utilities states that a comprehensive approach using the current New England method should be appropriate. Northeast Utilities contends that the existing cost allocation rules in the ISO-New England OATT would meet the proposed requirements for regional cost allocation with the addition of a clearer cost allocation method for economic projects and a separately stated method for projects intended to meet public policy requirements.

678. Some commenters are concerned as to whether the Commission should allow different cost allocation methods for different facilities.[509] These commenters make several arguments: (1) New transmission facilities seldom serve one function and may provide general reliability and other benefits to the transmission system; (2) the benefits of a given project may vary over time; and (3) such designations have been the source of substantial delays and conflict as planning participants spend time and resources arguing over a project's designation.

679. Xcel states that while it does not oppose the concept of using different cost allocation mechanisms for projects with different drivers, it believes that an excessive amount of time is being spent splitting benefits into their component buckets. It argues that the appropriate focus of cost allocation methods instead should be determining the multiple benefits that any transmission projects provide to a planning region and its stakeholders. Xcel explains that one objective of the state transmission certification process is to ensure that, regardless of the initial driver, projects are ultimately scoped and right-sized to provide multiple benefits. Xcel thus argues that cost allocation methods should concentrate on identifying and measuring multiple benefits that transmission facilities provide, rather than developing a new cost allocation method for each initial project driver.

680. Multiparty Commenters express concern that there could be a proliferation of cost allocation designs if the Commission allows different cost allocation methods for different types of facilities and for interregional and regional planning processes. They believe that this will lead to protracted disputes about the function of a transmission facility.

681. Transmission Dependent Utility Systems believe that Cost Allocation Principle 6 could place too much discretion in the hands of the transmission providers, particularly in non-RTO/ISO regions, and they urge the Commission to require transmission providers to make these decisions in collaboration with customers. They state that including load serving entities in these discussions would go a long way towards alleviating their concern with having a separate cost allocation method for facilities driven by public policy requirements.

[509] *E.g.,* ITC Companies; Multiparty Commenters; NextEra; and Wind Coalition.

682. Several commenters seek clarification of Principle 6. New York ISO seeks clarification that public utility transmission providers may adopt cost allocation methods for different types of transmission projects without creating a specific cost allocation mechanism applicable solely to public policy projects. New York ISO states that the Proposed Rule appears to contemplate this and contends that such a clarification would be appropriate, especially for regions such as New York that do not currently have a rule requiring that public policy projects be constructed. New York ISO states that such cost allocation methods can and should be determined on a project-specific basis depending on the policy driving the agreed-upon transmission project.

683. Long Island Power Authority suggests that imposing a single regional cost allocation method for public policy driven projects may inhibit the development of transmission that facilitates the interconnection of renewable energy generation and would allocate costs of each public policy driven project to the same beneficiaries, leading to the assignment of duplicative costs to specific entities and to increases in rates that reduce, or possibly eliminate, an entity's ability to incur costs for its own renewable generation or energy efficiency goals. Long Island Power Authority therefore believes the Final Rule should not direct project costs to non-beneficiaries and not impose costs that prevent non-jurisdictional entities from satisfying their own lawful public policy goals.

684. Alliant Energy seeks clarification that for purposes of Principle 6 the terms ''region'' and ''regional'' cover the entire RTO or ISO footprint in the case where there is a Commission-approved planning region within an RTO or ISO, such as American Transmission within MISO. Alliant Energy contends that Principle 6 invites the opportunity for discrimination and unintended consequences if the Commission determines that a region could constitute a single transmission provider within the RTO or ISO footprint. It states that cost allocation policies within an RTO or ISO footprint must be consistent.

b. Commission Determination

685. The Commission adopts the following Cost Allocation Principle 6 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 6: A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[510] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

and

Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.[511] Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.[512]

686. We agree with the Pennsylvania PUC and others that transmission planning regions should be afforded the opportunity to develop a different cost allocation method for different transmission project types.[513] The development of such cost allocation method, however, rests with the public utility transmission providers participating in regional transmission planning processes in consultation with stakeholders. Cost Allocation Principle 6 permits but does not require the public utilities in a transmission planning region to designate different types of transmission facilities, and it permits but does not require the public utilities in a transmission planning region that choose to designate different types of transmission facilities to have a different cost allocation method for each type. However, we clarify that if the public utilities choose to have a different cost allocation method for each type of transmission facility, there can be only one cost allocation method for each type.

687. It may be appropriate to have different cost allocation methods for transmission facilities that are planned for different purposes or planned pursuant to different regional transmission planning processes, provided that these methods are applied consistently. In particular, in response to some commenters, we clarify that we are not requiring a distinct regional or interregional cost allocation method applicable solely to transmission facilities for Public Policy Requirements and that are selected in a regional transmission plan for purposes of cost allocation, but we allow it.

688. Moreover, as the Commission recognized in Order No. 890, states have a critical role with respect to transmission planning.[514] That role may be particularly important with respect to planning for transmission needs driven by Public Policy Requirements, where multiple states may be impacted by the selection (or cost) of a given transmission project needed to meet transmission needs driven by a particular state's Public Policy Requirement. Therefore, we strongly encourage states to participate actively not only in transmission planning processes in general, but specifically in the identification of transmission needs driven by Public Policy Requirements. We also note that agreements among states with respect to cost allocation may be particularly important for transmission facilities designed to meet transmission needs driven by Public Policy Requirements. States could pursue such agreements in various forms, including a committee of state regulators or through a compact among states that receives appropriate approval from Congress.

689. We leave it to each transmission planning region or pair of transmission planning regions to propose on compliance whether, and how, to distinguish between types of transmission facilities. We also note that a public utility transmission provider together with other public utility transmission providers in a transmission planning region, and an RTO or ISO, which is itself a public utility transmission provider, may have a single cost allocation method for all proposed transmission facilities or different methods for different types of transmission facilities. For example, cost allocation methods may distinguish among transmission facilities that are driven by needs associated with maintaining reliability, addressing economic considerations, and achieving Public Policy Requirements, all of which would be required to be considered in the regional transmission planning process as explained in this Final Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of transmission project currently have transmission planning procedures and cost allocation methods that refer only to the first two types of transmission projects. This Final Rule allows a public utility transmission provider through its participation in a transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three types is considered in the regional transmission planning process and there is a means for allocating the costs of each type of transmission facility to beneficiaries. In response to PSEG Companies, we clarify that a regional cost allocation method for one type of regional transmission facility or for all regional transmission facilities may include voting requirements for identified beneficiaries to vote on proposed transmission facilities.

690. However, a public utility transmission provider must have a regional cost allocation method for any transmission facility selected in a regional transmission plan for purposes of cost allocation. It may not designate a type of transmission facility that has no regional cost allocation method applied to it, which would effectively exclude that type of transmission facility from being selected in a regional transmission plan for purposes of cost allocation. In response to New York ISO and Long Island Power Authority, a transmission facility proposed to address a Public Policy Requirement must be eligible for selection in a regional transmission plan for purposes of cost allocation and must not be designated as a type of transmission facility for which the cost allocation method must be determined only on a project-specific basis. However, in contrast to what New York ISO's comment implies, the regional cost allocation method for such a transmission facility may take into account the transmission needs driven by a Public Policy Requirement, who is responsible for complying with that Public Policy Requirement, and who benefits from the transmission facility. 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.

691. As stated elsewhere, we decline to opine here on whether any existing processes satisfy Cost Allocation Principle 6 in the regional and

[510] ''Public Policy Requirements'' replaces ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs'' as defined in P 0 of this Final Rule.

[511] ''Public Policy Requirements'' replaces ''public policy requirements established by State or Federal laws or regulations that may drive transmission needs'' as defined in P 0 of this Final Rule.

[512] The word ''clearly'' has been added to this sentence to make it consistent with the last sentence in regional cost allocation Principle 6.

[513] We note that a method, such as a highway-byway method for a reliability project, may itself further distinguish types of facilities, for example by voltage, and allocate costs differently for each type.

[514] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.

interregional context. For example, if a region believes that its regional transmission planning process meets Regional Cost Allocation Principle 6 for all facilities, including transmission facilities driven by a Public Policy Requirement, it may submit evidence in support of this position in a compliance filing pursuant to this Final Rule.

692. Some commenters are concerned that designation of transmission facility type can result in substantial delay because transmission facilities may serve multiple functions and benefits and beneficiaries may vary over time. This concern should be addressed in each region's transmission planning process. However, we note that many regional transmission planning processes currently have mechanisms for distinguishing between types of transmission facilities, and there is no reason to believe that transmission facilities designation necessarily results in a substantial delay.

693. In response to Alliant Energy's comment, the Commission addressed this concern in the regional transmission planning section above.[515]

8. Whether To Establish Other Cost Allocation Principles

a. Commission Proposal

694. The Proposed Rule sought comment on whether additional principles should apply to cost allocation for either regional or interregional transmission facilities, and it asked commenters to submit and explain the need for those principles.[516]

b. Comments

695. Six Cities ask the Commission to include a new principle or a corollary requirement that the transmission planning processes include provisions to encourage cost containment, a point echoed in other comments on cost allocation.[517] The New England States Committee on Electricity also argues that the Commission should establish transmission cost control and review mechanisms to ensure that construction is performed as efficiently as possible and the costs incurred are reasonable.

696. ELCON and Associated Industrial Groups urge the Commission to adopt two technical principles related to the costs of new transmission investments being allocated on a representatively-determined capacity (MW) basis, not on an volumetric (MWh) basis and periodic adjustment of cost allocation to reflect changes in power flows.[518] However, ITC Companies do not support periodic adjustments of cost allocation and describe it as disruptive and potentially risky.

697. Other commenters propose principles that look to safeguard particular participants in the transmission planning process. For example, City of Los Angeles Department of Water and Power states that there should be appropriate safeguards that allow non-public utilities to seek required approvals before they are allocated costs for new transmission projects, and that participation in the regional transmission planning process by non-public utilities remain voluntary. Similarly, Transmission Dependent Utility Systems state that if a particular customer is not allowed to participate fully in a regional planning process, there should be a presumption that the customer is not receiving benefits from the regional plan.

698. San Diego Gas & Electric proposed policy changes for transmission projects that span multiple balancing authority areas and for which a voluntarily negotiated cost allocation arrangement proves feasible. Its proposed policy changes focused on payment by loads, allocation of costs to balancing authority areas that do or do not benefit, and encouragement for non-jurisdictional governmental agencies to adopt reciprocal cost allocation policies.

699. Michigan Citizens Against Rate Excess proposed three additional principles that limit transmission costs driven by public policy requirements to the state or states of origin,[519] that transmission cost recovery should not be a means to subsidize non-transmission projects, and that no state or region should shoulder the cost alone when benefits accrue to others as well, namely for reliability projects only.

700. PUC of Ohio maintains that the Commission should consider principles when considering any long-term transmission rate design that provide the utility the opportunity to recover an authorized revenue amount, is equitable, provides for customer understanding and rate continuity, minimizes customer impact and undue cost shifts, and recognizes the use and benefits of the transmission system.

701. Environmental Defense Fund, the Wilderness Society, and Western Resource Advocates recommended principles that they argue will assist in identifying the full range of benefits that must be accounted for when justifying a project.[520] They state that project costs should be allocated consistent with the range/distribution of benefits that are likely to accrue in both the near- and long-term, that the benefits of projects must include carbon emissions reductions and the attainment of other state and federal policy imperatives, and that beneficiaries under any beneficiaries-pay cost allocation policy be defined to include consideration of the myriad of beneficial outcomes described above, as well as other benefits likely to accrue to transmission system users over the life of the grid investment.

702. American Antitrust Institute states that the Commission should consider how cost-benefit tests for cost allocation and recovery can be designed to promote competition and encourages the Commission to carefully scrutinize cost allocation approaches based on voting rules that give incumbent utility transmission providers the ability to vote against economic transmission projects that benefit ratepayers.

703. Energy Consulting Group suggests that beneficiaries, including those receiving firm transmission service should to be obligated to pay the allocated costs of the improvements through a specified tariff rate and relieved of any obligations to pay current OATT rates for improvements.

c. Commission Determination

704. We agree with Six Cities, New England States Committee on Electricity, and others that cost containment is important. However, we decline to establish a corresponding cost allocation principle as recommended, primarily because cost containment concerns the level of costs, not how costs should be allocated among beneficiaries. While we understand and agree that those receiving a cost allocation are appropriately concerned

[515] *See* discussion *supra* section III.A.

[516] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

[517] *E.g.,* California Commissions; California Municipal Utilities; City of Santa Clara; Connecticut & Rhode Island Commissions; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Northeast Utilities; Northern California Power Agency; and Transmission Agency of Northern California. While San Diego Gas & Electric agrees that it is appropriate for commenters to seek safeguards with respect to cost overruns, it takes issue as a factual matter with California Municipal Utilities' inclusion of the Sunrise-Powerlink project as one that is a clear example that cost overruns are endemic.

[518] *See also* East Texas Cooperatives and Maine Parties.

[519] *See also* Electricity Consumers Resource Council and the Associated Industrial Groups and Public Power Council.

[520] *E.g.,* Environmental Defense Fund; Wilderness Society; and Western Resource Advocates. Sonoran Institute also proposes the second and third principles proposed by Environmental Defense Fund and Wilderness Society and Western Resource Advocates.

that the level of the cost being allocated should be controlled accordingly, we do not believe that a new principle or corollary requirement in this Final Rule is the appropriate mechanism to promote cost containment.

705. We have considered all the other additional principles proposed by commenters but decline to adopt them. We do not believe that any additional principles are necessary at this time. Moreover, we believe that many of the suggestions of commenters, if required by this Final Rule, would limit the flexibility we provide in this Final Rule for public utility transmission providers to propose the appropriate cost allocation method or methods for their transmission planning region or pair of transmission planning regions. If a commenter believes that one or more of its suggestions is consistent with the six principles we adopt herein, that commenter is free to work within a regional stakeholder process to see if its concerns could be addressed. We will permit each transmission planning region or pair of transmission planning regions to propose cost allocation methods that satisfy additional requirements that they deem necessary to meet the specific needs of that transmission planning region or transmission planning regions provided they are consistent with the cost allocation principles of this Final Rule. Any such requirements should be submitted as part of the cost allocation method or methods on compliance, along with an explanation of how they comply with the requirements of this Final Rule.

F. Application of the Cost Allocation Principles

706. The Proposed Rule addressed several potential applications of the cost allocation principles, seeking general comment on the appropriateness of these six cost allocation principles and how they should be applied to the costs of new regional and interregional transmission facilities that are eligible for cost allocation.[521]

1. Whether To Have Broad Regional Cost Allocation for Extra-High Voltage Facilities

a. Commission Proposal

707. The Commission declined in the Proposed Rule to address in the abstract and in the absence of a record whether several candidate cost allocation methods, either in use today in a region or proposed by some commenters, would satisfy the proposed regional and interregional cost allocation principles.

b. Comments on Cost Allocation for Extra-High Voltage Facilities

708. Several commenters recommend that the Commission establish a rebuttable presumption that the costs of extra-high voltage transmission facilities be allocated widely across a region.

709. NextEra argues that extra-high voltage lines, typically 345 kV and above, provide regional benefits, and that the Commission should require that every cost allocation method include a rebuttable presumption that the costs of such lines will be allocated widely. WIRES agrees, pointing out that this is essentially the approach taken in PJM for projects above 500 kV. NextEra suggests that those seeking to rebut this presumption in the context of a particular extra-high voltage project should bear the burden of showing they receive no benefits from the project. To accomplish this, NextEra recommends that the Commission adopt a *pro forma* transmission cost allocation method, and that transmission providers and stakeholders could either follow the *pro forma* model or propose a method that is consistent with or superior to that model. Multiparty Commenters also support a rebuttable presumption for extra-high voltage lines.[522] Similarly, AEP argues that extra-high voltage facilities provide regionwide benefits and the costs of such facilities should be allocated widely across a region. AEP also suggests that extra-high voltage AC facilities that interconnect electrical regions and that are identified as needed under the applicable interregional coordination agreement benefit both regions, and AEP states that the costs of such facilities should be allocated across those regions. Clean Line supports allocating the costs for extra-high voltage lines across the largest region possible.

710. Baltimore Gas & Electric submits that the Final Rule should apply highway/byway principles to projects that traverse RTOs and to projects within RTOs. It states that the cost allocation principles espoused in the Proposed Rule should be adopted, and that the Commission should at least allow for the Opinion No. 494 method to be continued in PJM,[523] regardless of the methods that are deemed appropriate for other RTOs.[524] However, Baltimore Gas & Electric states that other RTOs must maintain cost allocation mechanisms with respect to each other that provide for reciprocal treatment. It states that new, high voltage, RTO-approved facilities should be paid for uniformly by all rate zones because they provide significant benefits to all rate zones.

711. Several reply commenters oppose proposals to establish a rebuttable presumption for extra-high voltage facilities.[525] Large Public Power Council argues that such proposals cannot be squared with the cost allocation principle set forth in *Illinois Commerce Commission* that utilities cannot be required to pay for facilities from which its members derive no or only trivial benefits. Ad Hoc Coalition of Southeastern Utilities replies that there is no basis to presume that an extra-high voltage transmission overlay is beneficial to all customers, and that such a position is inconsistent with *Illinois Commerce Commission*. Ad Hoc Coalition of Southeastern Utilities emphasizes that the addition of extra-high voltage facilities can overload the underlying transmission system and change power flows, requiring upgrades to lower voltage lines and operational changes. Ad Hoc Coalition of Southeastern Utilities contends that broadly socializing the costs of extra-high voltage facilities could bias the integrated resource planning process total-cost analyses toward such facilities in that at least some of their costs will be spread throughout the region and not incurred by the utility causing the need for the facilities. Similarly, Southern Companies states that its integrated resource planning has not shown that extra-high voltage lines are a cost-effective, reliable solution to meeting identified transmission needs and that constructing such lines in the Southeast and then broadly socializing their costs over the entire load in the region would result in higher costs to consumers than implementing non-extra-high voltage solutions. Southern Companies also argue that such an approach would skew the evaluations of which transmission and non-transmission

[521] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 178.

[522] Multiparty Commenters append an analysis performed by CRA International that purports to show the widely dispersed benefits of extra-high voltage transmission facilities (CRA Study).

[523] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), Opinion No. 494–A, 112 FERC ¶ 61,082 (2008) (cost allocation methods for new transmission facilities that distinguished between facilities below and above 500 kV), *remanded*, *Illinois Commerce Comm'n* v. *FERC*, 576 F.3d 470 (7th Cir. 2009).

[524] Delaware PSC and American Forest & Paper also support PJM's cost allocation method for high voltage facilities. American Forest & Paper asserts PJM's method is preferable to the energy allocator method proposed in MISO.

[525] *E.g.*, Coalition for Fair Transmission Policy; Ad Hoc Coalition of Southeastern Utilities; Southern Companies; Large Public Power Council; East Texas Cooperatives; New England States Committee on Electricity; and APPA.

alternatives are the least cost means to meet an identified need. MEAG Power provides illustrations of how such a proposal could result in unjust and unreasonable rates. Coalition for Fair Transmission Policy argues that the CRA Study filed by Multiparty Commenters is flawed because it neglects to mention that in some cases extra-high voltage facilities impose costs on some parts of a region as well, and that such impacts can be ascertained only by examining specific projects. MEAG Power similarly asserts that the CRA study is flawed for a number of reasons, including the fact that it examines only the existing grid, omits several regions from its analysis and fails to estimate any dollar benefits accruing to any party.

712. In addition, in its reply comments, SoCal Edison disagrees with NextEra's proposal for a *pro forma* cost allocation agreement, arguing that there is not sufficient evidence to determine that such an approach is consistent with the principle that costs be allocated roughly commensurate with benefits.

c. Commission Determination

713. We are not persuaded to adopt a rebuttable presumption that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely across a transmission planning region. Such a presumption would be akin to a default cost allocation method which, as discussed above,[526] we do not adopt. For the same reason, we do not agree that a *pro forma* cost allocation method is appropriate.

714. The Commission recognizes and intends that several approaches to cost allocation may satisfy the principles adopted in this Final Rule. If it were otherwise, the offer of regional flexibility would be an empty offer. Therefore, we do not impose a single cost allocation method for any transmission planning region. If public utility transmission providers and their stakeholders in a transmission planning region reach a consensus that the costs of extra-high voltage facilities, such as 345 kV and above, should be allocated widely and that this would result in a distribution of costs that is at least roughly commensurate with the benefits received, and support this conclusion with evidence, they may submit the method to the Commission on compliance.

2. Whether To Limit the Use of Participant Funding

a. Commission Proposal

715. Following the presentation of these six cost allocation principles in the Proposed Rule, the Commission discussed their application to participant funding as a regional or interregional cost allocation method for satisfying these principles. The Commission explained that in transmission planning regions outside of the RTO and ISO footprints, many of the cost allocation methods that the Commission accepted in the Order No. 890 compliance proceedings rely exclusively on a ''participant funding'' approach to cost allocation, in which the costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.[527] The Commission proposed that participant funding is not a cost allocation method that would satisfy these principles. The Commission further noted that a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. However, the Proposed Rule did not prohibit voluntary participant funding for those that choose to use it.

b. Comments on Limiting Participant Funding

716. Many commenters generally agree that a cost allocation method based exclusively on a participant funding approach neither achieves the goal of timely development of building transmission facilities nor results in just and reasonable rates.[528] In support of this position, several commenters maintain that participant funding does not allocate the costs of new regional transmission projects to their multiple beneficiaries.[529] East Texas Cooperatives request that the Commission define the scope of acceptable benefits that may be considered, provide that cost allocation methods ensure that customers receive benefits commensurate with their share of costs, and conclude that participant funding is a failed cost allocation method.

717. Several commenters agree that the Commission should clarify what regional cost allocation approaches are not acceptable.[530] AWEA states that to ensure that future cost allocation proposals do not serve as barriers to transmission expansion, and can support transmission additions that are ''right sized'' to meet the long-term needs of the system, the Commission should specify when participant funding, and other such cost allocation methods, should not be allowed, or what level of participant funding it might find acceptable. NextEra argues that the use of participant funding should be minimized, and that the Final Rule should specify that costs of transmission projects identified through the transmission planning process cannot be allocated to generators because any other outcome would simply continue the status quo of discouraging development of new resources.

718. In contrast, other commenters argue that the Commission should promote flexibility, and continue to allow for participant funding of projects with voluntary agreements on cost sharing.[531] Some commenters appear to believe the Proposed Rule would prohibit the use of participant funding in all circumstances, not just for new transmission facilities in a regional transmission plan for purposes of regional cost allocation to regional beneficiaries. As a starting point, a few commenters state that the Commission has accepted and continues to accept rates using participant funding. For example, E.ON points out that the Commission approved negotiated rates for the Chinook and Zephyr merchant transmission projects, which it believes is evidence that participant funding may be of practical use and may have more widespread application as transmission customers are required to access electricity from renewable generation. Therefore, some commenters argue that the Commission first must present factual evidence that current cost allocation methods are unjust and unreasonable, or otherwise unduly discriminatory, which it has not done.

[526] *See* discussion *supra* section IV.E.1.

[527] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 121–28.

[528] *E.g.*, AWEA; East Texas Cooperatives; Gaelectric; ITC Companies; Multiparty Commenters; NextEra; Transmission Access Policy Study Group; Transmission Dependent Utility Systems; and WIRES.

[529] *E.g.*, AWEA; Gaelectric; Multiparty Commenters; and Transmission Dependent Utility Systems.

[530] *E.g.*, AWEA; ITC Companies; Multiparty Commenters; NextEra; and WIRES.

[531] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; Arizona Public Service Company; City of Los Angeles Department of Water and Power; Santa Clara; E.ON; Large Public Power Council; Nebraska Public Power District; Northern Tier Transmission Group; Salt River Project; Transmission Agency of Northern California; Tucson Electric; Washington Utilities and Transportation Commission; WestConnect; and Westar.

Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission argue that participant funding most closely follows ''but for'' cost causation principles, and Ad Hoc Coalition of Southeastern Utilities adds that it is most consistent with judicial precedent regarding what constitutes an appropriate cost allocation method. Similarly, many commenters contend that the participant funding approach has led to the building of transmission projects that meet the reliability and economic needs of customers, and state and local policy goals.[532] Ad Hoc Coalition of Southeastern Utilities emphasizes that a requestor pays approach has been the norm for intersystem transmission projects in both the electric and gas industries. Arizona Corporation Commission, Salt River Project, City of Los Angeles Department of Water and Power, and Tucson Electric state that, in the West and Southwest, the participant-funded method of cost allocation has not delayed construction of transmission facilities and has been effective. Northern Tier Transmission Group believes that facilitating willing parties to make rational business decisions has a higher probability of causing the construction of new transmission than does a situation where costs could be forced upon unwilling parties, as is contemplated by the Proposed Rule.

719. In its reply comments, Entergy states that it believes that participant funding is an appropriate pricing method and should not be excluded from consideration in the Final Rule. Entergy requests clarification that any adverse finding against participant funding would not apply to customer-specific requests for service under the *pro forma* OATT. It notes that the Commission provided this clarification in Order No. 890, and it suggests that the Commission had the same intent in the Proposed Rule. Entergy argues that the types of projects set forth in the Proposed Rule do not include customer-specific requests for service, and it explains that such requests are evaluated pursuant to specific OATT procedures that govern system impact and facilities studies, and are performed in consultation with the affected customer, not vetted through a regional stakeholder process. Entergy notes that upgrades necessary to meet the specific request are similarly constructed to meet the needs of the customers, and are not subjected to a cost-benefit test to identify beneficiaries. Entergy cites to its own proposal regarding customer-specific service requests that the Commission found ''will promote, not discourage, efficient investments.'' [533]

720. Some commenters that support participant funding as a cost allocation method raise concerns about overly broad socialization of costs absent such a mechanism.[534] Large Public Power Council adds that the potential for cost socialization will lead to the planning process becoming vastly more contentious. Southern Companies argue that the proposed reforms are not consistent with cost causation principles. Likewise, Transmission Agency of Northern California argues that broad socialization of costs among all transmission customers is inconsistent with cost causation principles. Avista and Puget Sound state that the cost allocation proposals appear to improperly shift costs to existing customers that do not participate in projects. American Forest & Paper is concerned about the potential for overly broad socialization of costs to diminish incentives for cost-effective planning.

721. Some commenters believe that existing participant funding cost allocation processes are adequate and do not see a need at this time to change those existing processes.[535] These commenters and others,[536] primarily located in the Western Interconnection, believe that voluntary coordination and cost allocation of transmission facilities are more appropriate, particularly given their experiences, and that a mandatory cost allocation requirement could impede the transmission planning process and unintentionally delay or impede the development of new transmission.[537] California Commissions contend that this voluntary approach has minimized disputes and litigation. Arizona Public Service Company, Tucson Electric, and others suggest that voluntary participant funding of projects has permitted participants to successfully engage in allocating costs for transmission projects in the Southwest.

722. Commenters note other challenges to restricting participant funding. For example, California Commissions explain that assessment of benefits and beneficiaries is particularly challenging for long distance interregional transmission that would access remote renewable resources, given the uncertainties surrounding the ultimate build-out, cost (and cost competitiveness), and long-term purchasers for these resources, which are greatly complicated by the fact that energy and renewable energy credits may be purchased separately. Xcel states that MISO included a proposed solution to the ''first move/free rider'' issue, namely, that a generator interconnection customer who funds network upgrades pays the entire cost of those upgrades, regardless of other parties who may use them. Xcel asks that the Commission encourage such flexible and innovative solutions to such issues, particularly as public policy requirements are incorporated into transmission planning processes.

c. Commission Determination

723. The Commission finds that participant funding is permitted, but not as a regional or interregional cost allocation method. If proposed as a regional or interregional cost allocation method, participant funding will not comply with the regional or interregional cost allocation principles adopted above. The Commission is concerned that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. Because of this, it is likely that some transmission facilities identified as needed in the regional transmission planning process would not be constructed in a timely manner, adversely affecting ratepayers. On the other hand, we agree that if the costs of a transmission facility were to be allocated to non-beneficiaries of that transmission facility, then those non-beneficiaries are likely to oppose selection of the transmission facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the transmission facility's construction. For this reason, we adopt the cost allocation principles above that seek, among other things, to ensure that any regional cost allocation method or methods developed in compliance with this Final Rule allocates costs roughly commensurate with benefits.

[532] *E.g.*, Ad Hoc Coalition of Southeastern Utilities; Arizona Corporation Commission; City of Los Angeles Department of Water and Power; and Tucson Electric.

[533] *Entergy Servs., Inc.*, 115 FERC ¶ 61,095, at P 168 (2006).

[534] *E.g.*, Arizona Public Service Company; Large Public Power Council; Nebraska Public Power District; WestConnect; and Transmission Agency of Northern California.

[535] *E.g.*, WestConnect; PUC of Nevada; Transmission Agency of Northern California; and Coalition for Fair Transmission Policy.

[536] *E.g.*, Arizona Public Service Company; Bonneville Power; Tucson Electric; and California Transmission Planning Group.

[537] *E.g.*, Arizona Public Service Company; California Commissions; and Western Area Power Administration.

724. We therefore disagree with commenters who challenge this Final Rule's limitation on the use of participant funding on the grounds that it is inconsistent with the cost causation principle. Through the cost allocation principles adopted above, we require in all cases that regional and interregional cost allocation methods result in the allocation of costs for new transmission facilities in a manner that is roughly commensurate with the benefits received by those who will pay those costs. In proposing any cost allocation method or methods on compliance, there must be a demonstrated link between the costs imposed through a cost allocation method and the benefits received by beneficiaries that must pay those costs. However, these principles do not in any way foreclose the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility. Indeed, the evaluation of the potential benefits and beneficiaries of a proposed transmission facility may facilitate negotiations among such entities, potentially leading to greater use of participant funding for transmission projects not selected in the regional transmission plan for purposes of cost allocation.

725. Thus, we will not permit participant funding to be the cost allocation method for regional or interregional projects that are selected in a regional transmission plan for purposes of cost allocation. However, we are not finding that participant funding leads to improper results in all cases. For example, a transmission developer may propose a project to be selected in the regional transmission plan for purposes of regional cost allocation but fail to satisfy the transmission planning region's criteria for a transmission project selected in the regional transmission plan for purposes of cost allocation. Under such circumstances, the developer could either withdraw its transmission project or proceed to ''participant fund'' the transmission project on its own or jointly with others. In addition, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding.

726. Ad Hoc Coalition of Southeastern Utilities and Arizona Corporation Commission have not shown why participant funding is uniquely the cost allocation method that most closely follows ''but for'' cost causation principles. In fact, established precedent argues against this claim. Cost causation principles specify that, ''[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred [because] without the expectation of its contributions, the facilities might not have been built, or might have been delayed.''[538] This statement embodies ''but for'' reasoning, and since participant funding does not in all cases capture all beneficiaries of new facilities, it cannot be said to be the cost allocation method that mostly follows ''but for'' cost causation principles.[539] Northern Tier Transmission Group argues that participant funding has a higher probability of causing the construction of new transmission facilities because it relies on willing parties and does not involve parties who are unwilling to bear costs and who will engage in litigation to oppose transmission project development. Yet nothing in this Final Rule precludes the use of participant funding for those transmission projects with the support of individual market participants. We find that Northern Tier Transmission Group's argument that other cost allocation methods will impair construction to be speculative and see no reason to conclude that other methods in fact will have this result.

727. In response to Transmission Agency of Northern California, Avista, and Puget Sound, we note that a limitation on participant funding is far from a mandate for broad cost socialization. There is nothing in our cost allocation reforms that requires broad socialization or supports improper cost shifting in violation of cost causation principles. As discussed fully above, our cost allocation principles require that costs be allocated roughly commensurate with the benefits received by those that pay those costs.

728. In any event, nothing in this Final Rule applies to existing transmission facilities with existing cost allocations or to transmission projects currently under development.[540]

729. In response to Entergy's request, we clarify that our cost allocation reforms in this Final Rule are not intended to modify existing *pro forma* OATT transmission service mechanisms for individual transmission service requests or requests for interconnection service.

[538] *Illinois Commerce Commission*, 576 F.3d 470 at 476.

[539] We discuss Ad Hoc Coalition of Southeastern Utilities' claim regarding the consistency of participant funding with judicial precedent on cost allocation methods below in section IV.F.2.

[540] *See also* discussion *supra* section III.A.3.

3. Whether Regional and Interregional Cost Allocation Methods May Differ

a. Commission Proposal

730. In the Proposed Rule, the Commission explained that the method used for allocating interregional transmission facility costs between any two transmission planning regions may be different from the method used by the public utility transmission providers located in either of those transmission planning regions to allocate the costs of new regional facilities. Additionally, the Commission proposed that the cost allocation method used by the public utility transmission providers located in a transmission planning region to allocate the costs of new regional facilities could be different from the cost allocation method by which the public utility transmission providers in the same transmission planning region further allocate costs to be borne by that transmission planning region pursuant to an agreed-upon method for allocating the costs of interregional facilities.[541]

b. Comments

731. Several commenters agree with the Commission's proposal that the method used for allocating interregional transmission facility costs may differ from the method used to allocate regional costs.[542] Georgia Transmission Corporation states that if an interregional coordination obligation would require entities to enter into agreements with neighboring regions, the Commission should specify that it would not require the transmission entity to accept the neighboring entity's cost allocation method. Indianapolis Power & Light states that the cost allocation provisions of an interregional coordination agreement should set forth how costs are divided between the regions and leave it up to the regions to determine how their shares are divided among their subregions/zones/customers. MISO Transmission Owners state that transmission providers and their stakeholders should be permitted to determine whether the cost allocation methods used for regional projects should apply to the transmission provider's share of interregional facilities.

732. ISO New England supports the preservation of a voluntary, flexible approach to interregional cost allocation that recognizes regional differences. It also states that the Final Rule should either clarify the manner in which

[541] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 176.

[542] *E.g.*, Georgia Transmission Corporation; Indianapolis Power & Light; MISO Transmission Owners; NEPOOL; and Northeast Utilities.

agreement on a cost allocation would be signified by each of the two regions or provide for flexibility in recognition of the mechanisms that may be most appropriate in light of the internal transmission planning processes of the paired regions.

c. Commission Determination

733. We find that the method or methods for interregional cost allocation used by two transmission planning regions may be different from the method or methods used by either of them for regional cost allocation. Also, the method or methods for allocating a region's share of the cost of an interregional transmission facility may differ from the method or methods for allocating the cost of a regional facility within that region.

734. Although the public utility transmission providers in a transmission planning region may choose to allocate their share of the costs of an interregional transmission facility using their regional cost allocation method or methods, we see no reason to require them to do so. Indeed, for a transmission planning region that shares the cost of regional transmission facilities broadly, it may be inappropriate to apply broad cost sharing for an interregional transmission facility that is found to benefit only part of that transmission planning region. In addition, an interregional transmission facility may be of such greater scale than most regional transmission facilities that it may result in different types of benefits and beneficiaries than for a regional transmission facility.

735. In response to Georgia Transmission Corporation, we clarify that we do not require the public utility transmission providers in a transmission planning region to accept the regional transmission planning method or methods of another transmission planning region with which it participates regarding interregional transmission coordination. Each transmission planning region would determine for itself how to allocate the costs of a new interregional transmission facility consistent with this Final Rule.

4. Recommendations for Additional Commission Guidance on the Application of the Transmission Cost Allocation Principles

736. Several comments recommend that the Commission provide additional guidance on how to apply the cost allocation principles.

a. Comments

737. A number of commenters provide additional suggestions on cost allocation methods. Duke states that without clear pricing guidelines that do more than restate general cost allocation principles, regional and interregional transmission projects will have trouble getting out of the starting gate. Pennsylvania PUC asserts that cost allocation principles and methods should be reasonably clear and explainable to all stakeholders so that development of a cost allocation paradigm can be effectively grasped by all participants. East Texas Cooperatives believe that the costs of all transmission facilities needed to maintain reliability or to deliver long-term resources to load serving entities should be rolled into the applicable zonal, regional, or interregional rate, and that individual cost allocation methods should clearly set forth a plan for identifying beneficiaries and allocating costs to them. Washington Utilities and Transportation Commission is concerned that necessary certainty on cost allocation would not be achieved if the Final Rule lacks detail on the standards to be applied when reviewing or approving cost allocations proposals and the Commission opts to develop more precise cost allocation policies on a case-by-case basis.

738. Federal Trade Commission encourages the Commission to consider providing stronger guidance regarding transmission cost allocation principles. It expresses its concern that unnecessary variance in allocation methods will have a disruptive effect on multi-area transmission proposals, akin to the disruptive effects that unnecessary diversity in methods for calculating available transmission capacity had on transmission services spanning multiple areas. Federal Trade Commission encourages the Commission to consider whether stronger guidance would promote consensus sooner and avoid creating a patchwork of transmission cost allocation methods that may not support broad, efficient regional markets and low-cost compliance with environmental and energy security policy initiatives.

739. WIRES states that, as proposed, the principles provide only the most general outer bounds of acceptable practice and do not specify the characteristics of cost allocation methods that the Commission is likely to consider just and reasonable. WIRES states that the use of a relatively complete set of principles affords the Commission an opportunity to help short-cut the endless debates about limited merits of participant funding in a network environment and about the extent to which the benefits of transmission can be quantified in specific instances.

740. Northwestern Corporation (Montana) asserts that new transmission lines should not be insulated from sharing a portion of the network costs and/or an allocation of the network revenue requirement because new transmission lines experience enhanced reliability by connecting to the network transmission system.

741. Illinois Commerce Commission urges the Commission to remove ''postage stamp'' cost allocation from the list of acceptable cost allocation methods.[543] It maintains that postage stamp cost allocation is highly unlikely to produce just, reasonable, and nondiscriminatory rates, and continuing to maintain it as a possible cost allocation method is paralyzing transmission expansion.

742. Other commenters make suggestions or requests for guidance that are similar to other commenters' recommendations for additional cost allocation principles discussed above. For example, some commenters suggest that cost allocation methods should be periodically recalculated or reevaluated. Many commenters believe that changes to transmission system topology and amendments to state policies could alter disbursement of benefits, so the Final Rule should require cost allocations to be periodically reviewed and recalculated.[544] Some of these commenters believe that permanent cost allocations may inhibit investing in transmission upgrades and that there should be periodic reassessments to address any unintended consequences.[545] For example, E.ON and East Texas Cooperatives suggest that cost allocation reevaluation should occur every five years. Pennsylvania PUC states that a cost allocation method should be designed to evolve and reflect system changes over time.

743. Ohio Consumers Counsel and West Virginia Consumer Advocate Division suggest that the Commission adopt a process that allows for expedited resolution of disputes over cost allocation that may arise during the regional planning process. ISO New

[543] ''Postage stamp'' here refers to regionwide allocation of the cost of a transmission facility.

[544] *E.g.,* Sunflower and Mid-Kansas; Electricity Consumers Resource Council and Associated Industrial Groups; PUC of Ohio; East Texas Cooperatives; E.ON; and Transmission Dependent Utility Systems.

[545] *E.g.,* Transmission Dependent Utility Systems; Sunflower and Mid-Kansas; E.ON; East Texas Cooperatives; and Massachusetts Municipal and New Hampshire Electric.

England recommends Commission-sponsored mediation or other alternative dispute resolution for interregional cost allocation to assist two regions on reaching agreement if they cannot do so.

744. Commenters also submitted comments suggesting multiple ways to allocate costs of public policy driven projects.[546] FirstEnergy Service Company believes the Commission should clarify that the cost causation principle, including the requirement that costs are at least roughly commensurate with benefits, applies with full force to public policy driven projects in the regional planning process. First Wind believes the Commission should seek state input and rely upon state judgment on cost allocation for projects flowing from state policy. NEPOOL and New England States Committee on Electricity believe that each region should have considerable flexibility to develop public policy cost allocations. Transmission Dependent Utility Systems notes that not all projects proposed to implement public policy are worthy of presumptive acceptance and should be rigorously scrutinized in the stakeholder process.

b. Commission Determination

745. The Commission appreciates interested commenters' views, suggestions and requests for additional Commission guidance regarding the development of an acceptable cost allocation method or methods to comply with the identified cost allocation principles for new regional and interregional transmission facilities. We believe, however, that the principles adopted in this Final Rule provide sufficient general guidance for public utility transmission providers. The principles establish threshold criteria for a cost allocation method or methods to facilitate the development of a just and reasonable and not unduly discriminatory or preferential cost allocation method or methods. Additionally, the principles afford public utility transmission providers in individual transmission planning regions the flexibility necessary to accommodate unique regional characteristics. The Commission is concerned that providing the additional guidance or limitations requested by commenters would unduly restrict this flexibility. As we explained above, the Commission recognizes the need for regions to retain some level of flexibility to account for specific regional characteristics, resource types, or policy mandates.

746. We emphasize, however, that any variations between regions must be consistent with the six cost allocation principles. For example, East Texas Cooperatives suggest periodic reevaluation of cost allocation methods to respond to system changes. We do not view such a proposal as inconsistent with the cost allocation principles adopted above and, as such, it could be presented and evaluated at the regional level and, if agreed upon, proposed to be implemented by that transmission planning region. However, the Commission declines to prescribe such a policy for all transmission planning regions nationwide.

747. With respect to comments regarding how to allocate costs for public policy driven transmission projects, as discussed above,[547] we are not requiring public utility transmission providers to use the same cost allocation method for public policy and other types of transmission facilities. Instead, as discussed for Cost Allocation Principle 6, we permit different regional and interregional cost allocation methods for different types of transmission projects. Thus, whether each region or pair of transmission planning regions has a separate cost allocation method for public policy driven transmission projects depends on the consensus within that transmission planning region or those transmission planning regions, and we will not prescribe a uniform method for such transmission projects.

748. In response to Illinois Commerce Commission, the Commission declines to find in advance that a ''postage stamp'' cost allocation may not be an acceptable cost allocation method. If public utility transmission providers in a region, in consultation with their stakeholders, agree to such a method, and it is demonstrated to be consistent with the cost allocation principles and is supported with an appropriate assessment of benefits, then such an allocation may be submitted to the Commission on compliance, and the Commission will determine then whether the method meets its requirements.

749. We also clarify that, by establishing the six principles for regional and interregional cost allocation, the Commission is not attempting to supersede the cost causation principle. Rather, these six principles serve as guidelines for public utility transmission providers to use to create cost allocation methods that are consistent with the cost causation principle.

750. With regard to the concerns of Ohio Consumers' Counsel, West Virginia Consumer Advocate Division, and ISO New England about dispute resolution, the Commission believes that the dispute resolution processes in place under Order No. 890, enhanced as may be necessary to comply with our transmission planning reforms, will be adequate to address in the first instance, any disagreements that may arise regarding the allocation of transmission costs. The Commission reviewed and approved all of the dispute resolution procedures currently in place during our review of the compliance filings in response to Order No. 890, requiring enhancements in a number of cases.[548] We will review any changes to those dispute resolution procedures in response to compliance filings submitted in response to this Final Rule.

G. Cost Allocation Matters Related to Other Commission Rules, Joint Ownership, and Non-Transmission Alternatives

751. Commenters also raised cost allocation issues related to generator interconnection costs in Order No. 2003,[549] pancaked transmission rates policy in Order No. 2000,[550] transmission rate incentives in Order No. 679,[551] the relationship of this proceeding to the proceeding on variable energy resources, Docket No. RM10–11–000, and joint transmission ownership.

[546] *E.g.,* FirstEnergy Service Company; First Wind; NEPOOL; New England States Committee on Electricity; New England Transmission Owners; Public Power Council; and Transmission Dependent Utility Systems.

[547] *See* discussion *supra* section III.E.7.

[548] *See, e.g., Idaho Power Co.,* 128 FERC ¶ 61,064 at P 30–40; *Duke Energy Carolinas, LLC,* 127 FERC ¶ 61,281, at P 38–41 (2009); *New York Indep. Sys. Operator, Inc.,* 125 FERC ¶ 61,068, at P 61–64 (2008).

[549] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 68 FR 49846 (Aug. 18, 2003), FERC Stats. & Regs. ¶ 31,146, at P 676 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (DC Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[550] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *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 County, Washington* v. *FERC,* 272 F.3d 607 (DC Cir. 2001).

[551] Order No. 679, 71 FR 43294, FERC Stats. & Regs. ¶ 31,222, *order on reh'g,* Order No. 679–A, 72 FR 1152, FERC Stats. & Regs. ¶ 31,236, *order on reh'g,* 119 FERC ¶ 61,062.

1. Whether To Reform Cost Allocation for Generator Interconnections

752. In the Proposed Rule, the Commission did not propose to alter the cost recovery provisions of its generator interconnection rules.

a. Comments

753. Several commenters address the interaction between Order No. 2003 and the cost allocation requirements of this Final Rule. For example, Duke seeks clarification that impacts on transmission owners in neighboring regions resulting from a specific generator interconnection or transmission service request will continue to be addressed under the existing generation or transmission interconnection arrangements. East Texas Cooperatives urge the Commission to require development of an integrated process for studying network and point-to-point transmission service requests and generator interconnection requests that affect neighboring regions.

754. Other commenters address the interaction between Order No. 2003 and the transmission planning requirements. For instance, Solar Energy Industries and Large-scale Solar state that the Commission should require transmission providers to coordinate the transmission planning study process with the generator interconnection study process. PPL Companies agree stating that this would ensure that interconnection customers and native load bear their fair share of the costs of new transmission. On the other hand, NextEra believes that the costs of transmission projects identified through the transmission planning process should not be allocated to generators.

755. Some commenters urge the Commission to reevaluate the cost responsibilities in Order No. 2003 because they believe these are being used to circumvent the transmission planning process, creating a situation where load serving entities are forced to finance projects without project beneficiaries being identified.[552] If this continues, Bay Area Municipal Transmission Group asserts that greater transparency in the interconnection process is needed to facilitate the determination of the most cost-effective interconnection alternative. California Municipal Utilities argue that, if the costs of network upgrades identified through generator interconnection studies are borne by load within a region, those upgrades should be examined by the regional transmission planning process as a necessary precondition to approval by the relevant transmission provider. Six Cities note that the California ISO had represented in an Order No. 890 compliance filing that all interconnection-related network upgrades would be submitted through the request window open in each planning cycle and evaluated in the transmission planning process. Northern California Power Agency asserts that the generator interconnection process includes a loophole whereby transmission providers can circumvent the transmission planning process by proposing individual projects that are constructed by transmission providers, and recommends that the Commission limit the use of interconnection-related upgrades by ensuring they are a cost-effective means of grid expansion.

756. Several commenters discuss cost allocation for generation interconnection in the context of public policy projects. For example, Imperial Irrigation District asks the Commission to clarify that generation interconnection customers and their off-takers can be allocated the costs of public policy projects under the principles developed by transmission providers in each region when those generation project developers and their off-takers cause the need for or benefit from the public policy projects. In its reply comments, City of Santa Clara agrees with Imperial Irrigation District. Old Dominion agrees with PJM that greater clarity is needed regarding the extent to which the Commission is proposing that cost allocation for public policy driven projects depart from the existing Order No. 2003 framework. Old Dominion recommends that the Commission require all transmission providers to describe in their respective transmission planning and cost allocation tariff filings specific rules governing cost allocation for such projects.

757. East Texas Cooperatives state that they support a cost allocation policy under which the costs of network upgrades required to serve the native load of a transmission provider's network customers are rolled into the transmission provider's rates. They recommend that if a network upgrade is needed to accommodate an interconnection request for a generating facility that has not been designated as a network resource or is not otherwise contractually committed to serve customers within the transmission provider's footprint on a long-term basis, the interconnecting customer should be required to pay for the cost of network upgrades that would not have been required but for the interconnection request. They state that applying this policy would provide a level of assurance that the cost of such facilities will be allocated roughly commensurate to the estimated benefits.

758. Northern Tier Transmission Group asserts that, if a transmission provider does not execute an interconnection agreement with a generator, then the transmission provider has no mechanism to assess costs upon the generator. Northern Tier Transmission Group states that, to the extent the Commission chooses to address this practical issue, it should be done in the context of the generator interconnection procedures and agreements and not in the context of transmission planning.

759. In response, California ISO argues that such suggestions are beyond the scope of this proceeding and, if the Commission wishes to overhaul Order No. 2003, it should do so in a separate rulemaking so that parties have adequate notice that the Commission is proposing to modify its *pro forma* large generator interconnection procedures. Replying to Six Cities, California ISO argues that their assertion is based on a misconception that interconnection-related network upgrades need to be approved through the transmission planning process. California ISO states that Order No. 890 did not apply to such network upgrades.

b. Commission Determination

760. The Commission agrees with the California ISO and other commenters that issues related to the generator interconnection process and to interconnection cost recovery are outside the scope of this rulemaking. Order No. 2003 sets forth the procedures for the interconnection of a large generating transmission facility to the bulk power system. This Final Rule does not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities. Therefore, this Final Rule is not the proper proceeding for commenters to raise issues about the interconnection agreements and procedures under Order

[552] *E.g.,* Bay Area Municipal Transmission Group; California Municipal Utilities; and City of Santa Clara.

Nos. 2003,[553] 2006[554] or 661.[555] However, in not addressing these issues here, we are not minimizing the importance of evaluating the impact of generation interconnection requests during transmission planning, nor limiting the ability of public utility transmission providers to use requests for generator interconnections in developing assumptions to be used in the transmission planning process.

2. Pancaked Rates

a. Comments

761. A few commenters ask the Commission to address the pancaking of rates within transmission planning regions. Transmission Dependent Utility Systems assert that the Proposed Rule should eliminate regional rate pancaking as it remains a significant financial dilemma for many transmission customers and is destructive to regional planning. Transmission Dependent Utility Systems submit that if the Commission is going to implement a requirement for regional cost allocation, it should, at a minimum, eliminate pancaked rates unless there is an existing regional cost allocation method in place.

762. Sunflower and Mid-Kansas, on the other hand, contend that the Commission should modify its ''no pancaking'' policies for an RTO or ISO because the policy is not appropriate for large interregional projects and will potentially create extremely high rate increases for customers.

763. Gaelectric North America explains that merchant transmission developers are creating new pancaked rates. It asserts that, as public utilities construct radial merchant lines and allocate their costs through participant funding, they are creating additional pancaked rates for new generation owners who may wish to utilize these new facilities. Gaelectric North America argues that such pancaked rates inhibit the development and use of renewable resources. Further, it states that stringing radial transmission over network facilities is inefficient and pursued only to avoid appropriate cost allocation.

b. Commission Determination

764. We decline to make new findings with respect to pancaked rates in this Final Rule as it is beyond the scope of this proceeding. In particular, we do not make any modifications to the Commission's pancaked rate provisions for an RTO under Order No. 2000. If rate pancaking is an issue in a particular transmission planning region, stakeholders may raise their concerns in the consultations leading to the compliance proceedings for this Final Rule or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.

3. Transmission Rate Incentives

765. In the Proposed Rule, the Commission did not propose to alter its transmission rate incentive policies of Order No. 679.

a. Comments

766. Some commenters suggest that the Commission revisit its policy on transmission rate incentives, as set forth in Order No. 679. For example, they relate the Commission's proposals regarding nonincumbent transmission developers to transmission rate incentives.[556] Transmission Access Policy Study Group suggests that the Commission could require an incumbent transmission provider that exercises a federal right of first refusal to own and build a transmission facility to forgo any incentives on that facility. It argues that an incumbent transmission owner that exercises a federal right of first refusal should not then be given an incentive as necessary to encourage it to construct needed transmission. Minnesota Public Utilities Commission and Minnesota Office of Energy Security believe that one reason a federal right of first refusal may be justified is because there are instances where an incumbent transmission provider's rate of return is significantly lower than the incentive rate of return the Commission has approved for nonincumbent transmission developers. ITC Companies replies that such instances only demonstrate that different transmission incentives have been awarded in different cases by different regulatory bodies, noting that there are a variety of approved utility ROEs across the industry.

767. Other commenters tie the Commission's cost allocation proposals to transmission rate incentives. For example, APPA states that there is a clear causal connection between thorny cost allocation concerns and the Commission's incentive policy. APPA argues that when excessive transmission rate incentives are awarded to project sponsors, no one benefits from the associated costs except for the sponsors. Transmission Access Policy Study Group also suggests that the Commission use this opportunity to reevaluate application of Order No. 679 so that it does not add burdens on the economy or make siting and cost allocation issues more difficult than they already are. Transmission Dependent Utility Systems also state that transmission providers should be able to recover only the costs associated with a major transmission project through formula rates if that project was a product of an Order No. 890-compliant planning process that also meets the requirements of the Final Rule.

768. Joint Commenters recite cases in which project developers have been granted rate incentives that they believe substantially exceed the incentives that would result in just and reasonable rates. Joint Commenters also assert that the Commission has failed to recognize that the financial ground has shifted, citing the recent recession, historically low interest rates, and high unemployment. According to Joint Commenters, the rate of return needed to attract investment in a long-lived asset used to provide monopoly service is less than it was a few years ago. Finally, Joint Commenters recommend that the Commission revisit two features of its 1992 incentive rate policy statement,[557] concerning the requirement that incentive rate mechanisms be symmetrical and the requirement that applicants quantify the benefits to ratepayers as the incentive payment is awarded, arguing that these principles are equally important today. In its reply comments, Illinois Commerce Commission generally agrees with Joint Commenters, as does Organization of MISO States.

769. Pacific Gas & Electric recommends that the Commission clearly signal in the Final Rule that rate incentives are available for utilities that dedicate resources to the successful development of needed regional projects. In particular, Pacific Gas & Electric suggests that incentives for partnership in the development of major backbone projects crossing multiple

[553] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (DC Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[554] Order No. 2006, 70 FR 34189, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, 70 FR 71760, FERC Stats. & Regs. ¶ 31,196, *order granting clarification,* Order No. 2006–B, 71 FR 42587, FERC Stats. & Regs. ¶ 31,221.

[555] Order No. 661, 70 FR 34993 (Jun. 16, 2005), FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198.

[556] *E.g.,* New England States Committee on Electricity; Transmission Access Policy Study Group; and Southern California Edison.

[557] *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities,* 61 FERC ¶ 61,168 (1992).

jurisdictions are appropriate. Pacific Gas & Electric suggests that incentives should be offered for partnerships to both independent transmission companies and incumbent utilities, and that the incentives should be conditioned upon establishment of development arrangements that ensure consistent design standards are used that are compatible with the incumbent system, ongoing coordination of maintenance arrangements by responsible entities, and proper bilateral interconnection or coordinated operation agreements that will ensure the continuity and sustained reliability of the system.

770. However, a number of commenters oppose calls to reopen Order No. 679 in this proceeding.[558] Several commenters argue that such comments are beyond the scope of this rulemaking. They note that Order No. 679 was implemented in response to the direction of Congress, codified in section 219 of the FPA, to incent transmission investment. Some commenters note that Order No. 679 does not undermine transmission planning and cost allocation processes because the grant of incentives is conditioned on approval of the project under the relevant regional transmission planning processes. APPA states that it opposes blanket statements supporting the applicability of incentives under Order No. 679, and notes that Pacific Gas & Electric's request is illuminating because it shows how accustomed investor-owned utilities have become to obtaining such incentives and how they assume the Commission will simply rubber stamp in advance their requests for more incentives.

b. Commission Determination

771. We acknowledge commenters concerns regarding the Commission's policy on transmission rate incentives under Order No. 679. However, we decline to revisit or modify our policy under Order No. 679 in this Final Rule, as it is beyond the scope of this proceeding.[559]

4. Relationship of This Proceeding to the Proceeding on Variable Energy Resources

a. Comments

772. APPA argues that, contrary to the Commission's decision not to address transmission planning and cost allocation issues in its proceeding on the integration of variable energy resources (VER), Docket No. RM10–11–000, it believes that the two issues are not easy to compartmentalize. According to APPA, effective integration of VERs into regional transmission systems depends in large part on the availability of transmission facilities to support such integration, which in turn raises the issue of who will pay for the additional transmission facilities needed to undertake this integration effort. Thus, APPA urges the Commission to consider the tariff modification issues raised by VERs integration together with the need to develop cost allocation methods to pay for the additional transmission facilities that such integration requires.[560]

773. In its reply comments, Exelon argues that the Commission should address in this proceeding the operational issues entailed in integrating large amounts of VERs onto the grid in tandem with its rules for transmission planning and cost allocation. It states that whether or not the Commission issues a single rule in these dockets, it should rely on the record developed in the VERs rulemaking proceeding in deciding the Final Rule here, arguing that the record in the VERs proceeding fully supports the Commission requiring full accounting for the costs of integrating wind and other variable resources.

b. Commission Determination

774. This Final Rule establishes minimum requirements to guide the affected entities in developing their own transmission planning processes and cost allocation methods, which then will be submitted for filing with the Commission. The requirements established by this Final Rule apply to transmission planning and cost allocation for all resources. The VERs proceeding, however, addresses operational issues. To the extent that entities consider it necessary or appropriate to consider such operational issues in this Final Rule, they may do so by making a separate section 205 filing rather than raise issues on compliance in this proceeding.

5. Joint Ownership

a. Comments

775. A number of commenters urge the Commission to consider joint transmission ownership as a financing and cost allocation tool within the Proposed Rule. APPA and Six Cities ask the Commission to promulgate a rule favoring joint transmission ownership and to require that eligibility for rate incentives depend on an applicant's showing that it has offered reasonable opportunities for joint transmission ownership. APPA asserts that joint ownership diversifies financial risks and reduces the overall costs of the project as well as the need for transmission incentives. Transmission Access Policy Study Group and Transmission Agency of Northern California state that joint ownership leads to a more collaborative process in planning and development for both pooled systems and load serving entities. Transmission Access Policy Study Group states that joint ownership results in more diverse generation scenarios, shorter permitting processes during siting, and simpler resolutions of cost allocation issues, and points out that joint ownership spreads the risk of projects and provides a variety of sources of capital for projects.

b. Commission Determination

776. Specific financing techniques such as joint ownership are beyond the scope of this proceeding. Transmission developers are, of course, free to consider joint ownership when proposing and developing a transmission project. Just as we are not requiring any specific cost allocation method, we do not specifically address joint ownership as a cost allocation tool in this proceeding. However, we reiterate here our statement in Order No. 890 that we believe there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.[561]

6. Cost Recovery for Non-Transmission Alternatives

a. Comment Summary

777. GridSolar suggests that the Commission require utilities and RTOs/ISOs to evaluate alternatives to traditional transmission solutions on the same basis, using the same standards as those used for traditional transmission solutions, and that this could be done through a competitive solicitation. GridSolar notes that distributed energy resources connect at voltages below 69 kV and therefore do not qualify for cost allocation treatment under the

[558] *E.g.,* AEP; Edison Electric Institute; EIF Management; ITC Companies; National Grid; Pacific Gas & Electric; and PSEG Companies.

[559] The Commission issued a Notice of Inquiry on May 19, 2011 regarding its policy on transmission incentives under Order No. 679. *See Promoting Transmission Investment Through Pricing Reform,* Notice of Inquiry, 135 FERC ¶ 61,146 (2011).

[560] APPA also incorporates by reference the comments it submitted in Docket No. RM10–11–000.

[561] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 593.

transmission planning process although they provide the same services as other transmission resources. Similarly, 26 Public Interest Organizations argue that transmission and non-transmission solutions should be treated comparably for cost recovery purposes.

778. FirstEnergy Service Company argues that while the Proposed Rule does not address cost recovery for non-transmission projects, only the costs of facilities that perform a transmission function (including energy storage projects) should be included in transmission rates. FirstEnergy Service Company argues that regional transmission planning processes should not be a vehicle for owners of generation or demand side management projects that are eligible to earn revenue from sales of energy, capacity, and ancillary services to earn subsidies from transmission customers.

b. Commission Determination

779. As we make clear above in the section on Regional Transmission Planning, we are maintaining the approach taken in Order No. 890 and will require that generation, demand resources, and transmission be treated comparably in the regional transmission planning process.[562] However, while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, we conclude that the issue of cost recovery for non-transmission alternatives is beyond the scope of the transmission cost allocation reforms we are adopting here, which are limited to allocating the costs of new transmission facilities.[563]

V. Compliance and Reciprocity Requirements

A. Compliance

1. Commission Proposal

780. With the exception of the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within six months of the effective date of the Final Rule in this proceeding. With regard to the proposed interregional transmission coordination and interregional cost allocation requirements, the Proposed Rule would require each public utility transmission provider to submit a compliance filing within one year of the effective date of the Final Rule in this proceeding.[564] The Commission proposed that it would assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of the Proposed Rule.

2. Comments

781. Exelon urges the Commission to adhere to its original time schedule for compliance filings of six months for intraregional transmission planning and one year for interregional agreements. In its reply comments, LS Power argues that the six-month and twelve-month compliance deadlines are far more generous than the 60-day deadline that the Commission provided for compliance with Order No. 888 and the filing of revised power pooling and multilateral coordination agreements, respectively.

782. Some commenters suggest that the Commission extend the compliance deadlines for up to three years.[565] Indianapolis Power & Light and SPP state that the proposed six-month and one-year deadlines do not allow sufficient time for the stakeholder process. Indianapolis Power & Light states that this is particularly true if the right of first refusal is removed and recommends that the Commission extend the deadlines by a minimum of one year. SPP recommends that the Commission extend the proposed deadline for regional transmission planning by at least six months and for interregional transmission planning and cost allocation to three years. MISO Transmission Owners state that the Commission should extend all compliance deadlines by a minimum of six months. Arizona Corporation Commission states that the Commission should recognize that most public utility transmission providers in the West are not members of an RTO and will need more time, perhaps 24–36 months, to draft regional and interregional transmission plans. Arizona Public Service Company agrees in is reply comments that the compliance deadlines are too aggressive, arguing that the Commission is proposing a vast array of changes that will require utilities to develop positions, collaborate with neighboring utilities, and reach consensus with regional groups.

783. Western Area Power Administration recommends that, in lieu of compliance filings, the Commission require transmission providers to file periodic status reports regarding intraregional and interregional efforts. As an alternative approach, it recommends that the Commission extend the compliance filing deadline to one year for intraregional transmission planning and cost allocation issues and two years for interregional issues. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council recommend that in lieu of the proposed one-year compliance filing requirement, that the Commission call for status updates on these matters in one year's time, potentially to be followed by further orders on a regional basis establishing reasonable timeline targets.

784. Focusing on the six month regional planning compliance deadline, some commenters express the view that six months is a reasonable compliance period.[566] LS Power notes that many of the commenters expressing opposition to the six-month compliance deadline are the same entities that are opposed to removal of the federal right of first refusal, suggesting that any extension of compliance periods not apply to the federal right of first refusal from jurisdictional OATTs and agreements.

785. Other commenters express concern about the ability of transmission providers to meet the six-month compliance filing requirement for regional transmission planning requirements.[567] New England States Committee on Electricity states that a Final Rule addressing the rights and obligations of nonincumbent transmission providers within the regional planning process should provide the planning regions adequate time to sort through a means of complying. Xcel urges the Commission to allow entities in the Western Interconnection sufficient time and latitude to develop mechanisms that effectively meet the needs of the region; it states that, given the needs of the western region, six months or even one year is an unreasonably short period of time to build a structure to comply with the Commission's regional transmission planning requirements. Washington Utilities and Transportation Commission states that the Commission need not proceed with urgency but

[562] *See* discussion *supra* Section III.A.

[563] As we stated in the Proposed Rule, the Commission has recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes. *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at n.58 (citing *Western Grid Development, LLC,* 130 FERC ¶ 61,056 (2010)).

[564] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 179.

[565] *E.g.,* Indianapolis Power & Light; SPP; MISO Transmission Owners; Arizona Corporation Commission; and Arizona Public Service Company.

[566] *E.g.,* Northwest & Intermountain Power Procedures Coalition and LS Power.

[567] *E.g.,* New England States Committee on Electricity and Xcel.

should allow existing regional processes to mature, which may lead to a more expeditious and effective transmission planning process.

786. Focusing on the one year interregional compliance deadline, East Texas Cooperatives state that, given the urgent need for interregional transmission planning reform, the Commission should require filing of interregional transmission planning agreements within six months of the effective date of the Final Rule. In its reply comments, East Texas Cooperatives add that shortening this deadline would motivate transmission providers to improve coordination with their adjacent regions. Exelon states that for sets of regions that currently have Commission-approved joint operating agreements, the Commission should require a six-month compliance filing.

787. Other commenters contend that the one-year time period for compliance filings relating to interregional transmission planning agreements is unworkable. Southern Companies doubt that an interregional cost allocation agreement could be developed in the Southeast within the proposed one-year deadline. ISO/RTO Council states that this proposal is unworkable due to the complexity, limited resources, the need to involve stakeholders, and potentially the number of agreements to be reached. NV Energy agrees, stating that significant additional time is needed to address interregional transmission agreements and cost allocation issues given the number of parties involved. Xcel agrees that the proposed one-year deadline is unattainable and the Commission should allow more time for interregional planning and cost allocation initiatives to develop voluntarily.

788. Duke and Georgia Transmission Corporation state that the Commission should provide two years to submit interregional transmission planning agreements, given the number of parties that may be involved and the difficulties of developing cost allocation methods. Edison Electric Institute requests that the Commission be flexible regarding compliance deadlines for interregional agreements and cost allocation and consider allowing up to two years for compliance. Pennsylvania PUC states that interregional agreements will require many actions internal to RTOs and ISOs and planning organizations, therefore the Commission should consider expanding the compliance period from one year to 18 or 24 months.

789. With regard to compliance filings by RTOs and ISOs, New York ISO argues that the Commission should narrow the scope of the compliance filings required under the Final Rule so that RTOs and ISOs are not effectively compelled to demonstrate compliance with requirements that they have already satisfied in their individual Order No. 890 planning proceedings. Several commenters also urge the Commission to consider existing RTO or ISO cost allocation methods as compliant with the proposed cost allocation principles and to avoid reopening debates about regional cost allocation methods already approved by the Commission.[568] Some of these commenters argue that existing processes, such as those used in California ISO and ISO New England, are reasonable[569] while others disagree.[570]

790. Several commenters state that the Commission should not lightly change existing regional cost allocation methods.[571] For example, Duke states that parties challenging the appropriateness of an existing Commission-approved method should bear a heavy burden of showing why that method is inconsistent with the Final Rule. Transmission Dependent Utility Systems state that the Commission should not automatically disrupt current regional cost allocation methods but instead require compliance filings that demonstrate that the regional cost allocation method was indeed the product of an open and inclusive stakeholder process and that the regional cost allocation method either meets the Commission's proposed cost allocation principles, or that the existing regional cost allocation method is consistent with or superior to the requirement of those principles.

791. Additionally, MISO Transmission Owners, Indianapolis Power & Light, and SPP recommend that the Commission clarify that transmission owners in an RTO or ISO are permitted to participate in the compliance filing of the RTO or ISO without making a separate compliance filing of their own. Omaha Public Power District suggests that providers that are not members of an RTO be allowed to participate in the relevant RTO planning process to achieve the interregional planning mandate because this would reduce the cost of coordination and improve its efficiency and effectiveness.

3. Commission Determination

792. Given the various comments requesting a longer compliance period, we extend the compliance filing requirements set forth in the Proposed Rule. Accordingly, we find that, with the exception of the requirements with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods, each public utility transmission provider must submit a compliance filing within twelve months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth in this Final Rule.[572] The Commission also requires each public utility transmission provider to submit a compliance filing within eighteen months of the effective date of this Final Rule revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth herein with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods. As explained below, we expect that the twelve month and eighteen month deadlines provide sufficient time for each public utility transmission provider to meet the requirements of this Final Rule.

793. For those suggesting that current transmission planning and cost allocation initiatives should be allowed more time to develop, we find that the need to provide rates, terms and conditions of jurisdictional service that are just and reasonable and not unduly discriminatory or preferential, and the need to build new transmission facilities that more efficiently or cost-effectively support the reliable development and operation of wholesale electricity markets, requires that the reforms adopted in this Final Rule are implemented in a timely

[568] *E.g.,* California ISO; SoCal Edison; San Diego Gas & Electric; Eastern Mass. Consumer Owned System; Northeast Utilities; MISO; New York ISO; NEPOOL; New England States Committee on Electricity; Kansas Corporation Commission; and Xcel.

[569] *E.g.,* California PUC; Pacific Gas & Electric; NEPOOL; and Connecticut & Rhode Island Commissions.

[570] Several commenters, such as the Integrated Transmission Benefits Model Proponents and Maine Parties argue that ISO New England's current transmission planning and cost allocation methods do not comply with this Final Rule. These concerns should be raised during the stakeholder process used to develop compliance with this Final Rule. To the extent that a commenter believes that its concerns have not been resolved in the relevant compliance filing, it can raise those concerns at that time in a protest to the compliance filing.

[571] *E.g.,* Duke; New Jersey Board; Northeast Utilities; and Transmission Dependent Utility Systems.

[572] *See* Appendix C for the *pro forma* Attachment K consistent with this Final Rule.

fashion.[573] The Commission concludes that the time periods provided for adoption of these reforms—twelve months for regional transmission planning and cost allocation reforms and eighteen months for interregional reforms—are reasonable and achievable. These extended time periods provide additional time for public utility transmission providers to work with their stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein.

794. We find that the compliance time periods established in this Final Rule strike an appropriate balance between implementing needed reforms to transmission planning and cost allocation processes in a timely fashion and providing time for those involved in these processes to work with stakeholders to develop transmission planning and cost allocation processes that conform with the requirements adopted herein. Moreover, we believe these compliance filing deadlines are compatible with the interests of those that intend to develop transmission planning processes that take into account the lessons learned through the ARRA-funded transmission planning initiatives, discussed above in section I.C and III.C.I, under which the participants of each interconnection are currently collaborating on transmission planning to produce an initial long-term plan in mid-2012 and a final plan in 2013. For this same reason, we are not persuaded by those commenters that recommend that the Commission require periodic status reports in lieu of compliance filings.

795. In response to commenters' requests, we clarify that an RTO or ISO and its public utility transmission provider members may make a compliance filing that demonstrates that some or all of its existing RTO and ISO transmission planning processes are already in compliance with this Final Rule, and we will consider this demonstration and any contrary views on compliance. We require every public utility transmission provider, including an RTO or ISO transmission provider, to file its existing or proposed OATT provisions with an explanation of how these provisions meet the requirements of this Final Rule. While many of the existing transmission planning and cost allocation processes and methods may be similar to what this Final Rule requires, others may differ because this Final Rule's requirements expand on the Order No. 890 requirements. Whether an existing process was approved previously by the Commission is not dispositive of whether that process complies with this Final Rule.

796. We recognize that it is possible that some existing RTO and ISO transmission planning and cost allocation processes may already satisfy the Commission's proposal in whole or in part. However, we decline to rule generically, in the absence of a record based on a comparison of existing practices with the provisions of this Final Rule, on the degree to which a particular RTO or ISO may already be in compliance.

797. Furthermore, public utility transmission owners that are part of Commission-jurisdictional RTOs and ISOs may demonstrate compliance through that RTO's or ISO's compliance filing and are not required to make a separate compliance filing. This includes, in response to SPP, compliance with the interregional transmission coordination requirements to the extent an RTO or ISO has negotiated the necessary arrangements on behalf of its members. In response to Omaha Public Power District, we encourage both RTO and ISO members and those not in an RTO or ISO to work together regarding regional transmission planning. We neither prohibit non-RTO/ISO members that are geographically adjacent to and/or contiguous with an RTO/ISO from participating in the RTO/ISO's regional transmission planning process nor do we require an RTO/ISO to admit nonmembers to its regional transmission planning process. The decision on whether to combine their transmission planning efforts in this way to comply with the regional transmission planning and regional cost allocation requirements and the interregional transmission coordination requirements and interregional cost allocation requirements of this Final Rule is a decision that is best left to the individual entities as well as to the two regions in question. In addition, the OATT for the RTO or the ISO of which a public utility transmission provider is a part should include commonly agreed-to language describing that RTO/ISO's interregional transmission coordination with each neighboring transmission planning region.

798. In addition, in non-RTO/ISO regions, if public utility transmission providers in those regions decide to make combined compliance filings, they are free to do so. However, each public utility transmission providers' OATT must include the reforms required in this Final Rule.

B. Reciprocity

1. Commission Proposal

799. The Commission proposed that transmission providers that are not public utilities (*i.e.,* non-public utility transmission providers) would have to adopt the requirements of the Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[574] The Commission also stated that if it finds on the appropriate record that a non-public utility transmission provider is not participating in the proposed regional transmission planning and cost allocation processes set forth in this Final Rule, the Commission may exercise its authority under FPA section 211A [575] on a case-by-case basis.[576]

2. Comments

800. Some commenters question whether non-jurisdictional entities can legally be required to participate in regional and interregional transmission planning and cost allocation processes. Several non-jurisdictional entities suggest that they cannot. For example, Bonneville Power asserts that the proposed mandatory cost allocation reforms could conflict with its statutory obligations. Bonneville Power states that

[573] This finding is supported by our discussion above in section II.

[574] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 181 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63). Under the *pro forma* OATT, a non-public utility transmission provider may satisfy the reciprocity condition in one of three ways. First, 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. A non-public utility transmission provider using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility transmission provider then must offer service under its reciprocity tariff to any public utility transmission provider whose transmission service the non-public utility transmission provider seeks to use. Second, the non-public utility transmission provider may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility transmission provider may seek a waiver of the reciprocity condition from the public utility transmission provider. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[575] FPA section 211A(b) provides, in pertinent part, that ''the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services—(1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.'' The non-public utility transmission providers referred to in this Final Rule include unregulated transmitting utilities that are subject to FPA section 211A.

[576] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

it is required by statute to have Congressional approval before it can build facilities outside the Pacific Northwest or build major transmission facilities within the Pacific Northwest. Bonneville Power states that it is obligated to determine the appropriateness of its transmission expenditures, and those expenditures are subject to specific directives or limitations that Congress may include in its appropriation acts. As a result of these statutory obligations, Bonneville Power contends that it must retain the right to review each proposal and agree to any proposed allocation of costs from another party.

801. Western Area Power Administration states that it is a federal power marketing administration and must comply with statutory requirements that apply to such entities, such as the Anti-Deficiency Act, the Reclamation Project Act of 1939, and the Flood Control Act of 1944. Western Area Power Administration argues that these statutory requirements preclude involuntary cost allocation of third-party transmission facilities to it. Western Area Power Administration also argues that requiring it to incorporate a mandatory cost allocation share into its rates is inconsistent with the jurisdiction over, and power to review, Western Area Power Administration's rates that the Department of Energy delegated to the Commission.

802. Bonneville Power requests that the Commission explain the effect of reciprocity in the context of transmission planning and cost allocation. Bonneville Power states that if the Commission conditions reciprocity on adherence to the Proposed Rule, it requests that the Commission state in the Final Rule that it will accommodate deviations in compliance filings that are necessary to allow non-public utilities to participate. Bonneville Power contends that if the Commission does not accept regional deviations, coordinated regional planning and cost allocation will likely be unworkable for both public and non-public utilities in the Pacific Northwest.

803. Public Power Council asserts that the Commission's proposed cost allocation method will drive non-public utilities out of the voluntary planning process. Public Power Council states that governmentally-owned utilities are subject to state statutes that may limit their ability to enter into contracts involving unknown future costs and that bind future district commissions or city councils. Public Power Council thus argues that the Commission should either abandon its proposal to require binding cost allocation agreements for non-RTO areas or withdraw its proposal that voluntary participant funding cannot be the sole method of cost allocation when the transmission provider is not a participant in an RTO. Omaha Public Power District states that it is committed to voluntary participation in the transmission planning process. However, it also states that as a state political subdivision it is not subject to the Commission's general jurisdiction under the FPA and that the Commission has no authority to set rates for it without its consent.

804. Four G&T Cooperatives argues that the Commission does not have jurisdiction under the FPA to require non-public utilities to participate in regional transmission planning processes or to agree to regional cost allocation methods. It also argues that the reciprocity provisions under Order Nos. 888 and 890 and the *pro forma* OATT do not provide a basis for requiring non-public utilities to participate in regional transmission planning and cost allocation. National Rural Electric Coops state that the Commission has consistently refused to expand the reach of the reciprocity provision to include transmission customers other than those from which the non-public utility is taking service and those who are transmission-owning members of an RTO or ISO. G&T Cooperatives and National Rural Electric Coops request clarification that the Commission is not modifying the scope of the reciprocity requirement as established in Order Nos. 888, 890, and 890–A.

805. Western Grid Group, on the other hand, recommends that to engage non-jurisdictional utilities in regional planning groups, the Commission should make it clear that such participation is a requirement for Commission recognition of reciprocity tariffs and that all entities that share the grid have an obligation in the public interest to help plan its expansion and modernization.

806. SPP states that, consistent with the approach set forth in Order No. 890, the Commission should continue to encourage participation by non-jurisdictional entities in regional transmission planning processes. SPP also states that the Commission should consider requiring non-jurisdictional entities that have reciprocity tariffs on file with the Commission to modify those tariffs specifically to address the obligation to participate in the regional transmission planning process and cost allocation mechanism development. Similarly, San Diego Gas & Electric suggests that Order No. 888's reciprocity requirements be enforced, as necessary. Anbaric and PowerBridge also believe that the Final Rule should apply to all transmission providers, including to those subject to the Commission's reciprocity requirements.

807. A number of commenters also address the Commission's authority under FPA section 211A. National Rural Electric Coops argue that the Commission's jurisdiction under FPA section 211A is limited to requiring a subset of unregulated transmitting utilities to provide transmission services to others on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. National Rural Electric Coops asserts that it is concerned that the Commission may be interpreting FPA section 211A to mean that it could invoke the provision in circumstances other than those in which it makes a finding that an unregulated transmitting utility is not treating its transmission customers in a way that is comparable to the way it treats itself. National Rural Electric Coops request that the Commission clarify that it will address questions of non-comparable treatment on a case-by-case basis as necessary. National Rural Electric Coops state that such a clarification could help avoid unnecessary litigation.

808. Imperial Irrigation District questions the Commission's legal authority to allocate costs to non-public utilities via either the reciprocity principle or FPA section 211A. It states that cost allocation is a rate issue, and Congress has not authorized the Commission to set rates for non-public utilities. It argues that under the Commission's reciprocity principle, the Commission does not set rates of non-public utilities.

809. Large Public Power Council and Nebraska Public Power District state that the proposed reciprocity requirement would dramatically expand the commitment that non-public utilities were asked to make under Order No. 888 and ensuing orders and would greatly exceed the Commission's authority. They state that FPA section 211A does not permit the Commission to compel a non-public utility to contribute funding for regional or interregional transmission projects, nor would it enable the Commission to exercise any authority over the transmission planning or construction plans of a non-public utility. Sacramento Municipal Utility District urges the Commission to reconsider its proposal to invoke FPA section 211A

authority on a case-by-case basis. It states that this is unnecessary, beyond the limited reciprocity requirements of Order Nos. 888 and 890, and it is beyond the Commission's authority. Western Area Power Administration states that FPA section 211A does not authorize the Commission to require unregulated transmitting utilities to engage in regional transmission planning and cost allocation.

810. Western Area Power Administration and National Rural Electric Coops request clarification that the Commission did not intend its statements in the Proposed Rule regarding FPA section 211A and the reciprocity provisions of Order Nos. 888 and 890 to expand its authority over non-public utilities. Georgia Transmission Cooperative argues that the Commission has not provided evidence to support application of FPA section 211A and that applying it would be inconsistent with prior Commission statements that non-public utilities are not subject to the same cost allocation rules as public utilities.

811. Transmission Access Policy Study Group and Colorado Independent Energy Association support the Commission's proposal to invoke reciprocity for non-jurisdictional transmission providers as needed to achieve its goals, and they agree with the Commission's decision not to invoke its authority under FPA section 211A. Colorado Independent Energy Association also recommends that to avoid the use of FPA section 211A, the Commission should provide a *pro forma* OATT and a date certain for non-jurisdictional entities to report their progress to the Commission regarding incorporation of the principles set forth in the Proposed Rule into their OATTs and practices. Transmission Agency of Northern California believes that the demonstrated willingness of non-public utility transmission providers to comply voluntarily with Commission directives shows that an explicit requirement that they comply with the Proposed Rule is unnecessary.

812. Other commenters, including MidAmerican and NextEra, suggest that the Commission should apply reciprocity or exercise its authority under FPA section 211A to require non-public utilities to participate in regional and interregional transmission planning and cost allocation processes. MidAmerican states that the Commission has the authority to require all non-jurisdictional utilities to comply with, and remain subject to, the proposed transmission planning and cost allocation requirements and that the Commission should use this authority if it intends to achieve its stated objectives on a non-discriminatory basis. MidAmerican believes that failure to include all transmission providers will result in an inequitable burden for jurisdictional utilities and their customers, and it will create additional investment uncertainty for projects included in the regional plan. NextEra supports the use of FPA section 211A to extend the requirements of the Final Rule to unregulated transmitting utilities. It believes that invoking FPA section 211A on a case-by-case basis is risky and may not ensure maximum participation by unregulated utilities. AWEA states that the Commission should make clear its intention to invoke FPA section 211A as necessary to ensure needed participation in regional transmission efforts and cost allocation requirements.

813. Bonneville Power asserts in its response that neither the Proposed Rule, nor any of the initial comments, provide evidence that supports invoking FPA section 211A, either on a case-by-case basis or generically. Bonneville Power disagrees with MidAmerican that public utility transmission providers would be subject to undue discrimination if non-public utilities do not participate in transmission planning and cost allocation. It argues that any differences in treatment would result from adopting the Proposed Rule, not from discrimination by non-public utilities. Large Public Power Council disagrees that the Commission has authority under FPA section 211A to compel non-public utilities to participate fully in whatever planning and cost allocation rules are adopted in this proceeding. It also states that the Commission cannot accomplish indirectly through its reciprocity provisions what it cannot accomplish directly under the statute.

814. MidAmerican also suggests that the Commission use its conditioning authority to require non-jurisdictional utilities to participate in the regional transmission planning and cost allocation processes, stating that the Commission has already taken this approach under FPA section 215. However, in reply, Large Public Power Council disagrees, noting that section 215 explicitly extends Commission jurisdiction for reliability purposes over a wide range of entities, thereby confirming that express direction from Congress is required before the Commission can exercise jurisdiction over otherwise non-jurisdictional entities.

3. Commission Determination

815. To maintain a safe harbor tariff, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT as it has been revised by this Final Rule. As noted in the Proposed Rule, we are encouraged, based on the efforts that followed Order No. 890, that both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which gives us authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis. However, if the Commission finds on the appropriate record that non-public utility transmission providers are not participating in the transmission planning and transmission cost allocation process required by this Final Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

816. Given our decision above, we decline to adopt SPP's suggestion that the Commission require non-public utility transmission providers that have safe harbor tariffs on file to modify those tariffs specifically to address the transmission planning and cost allocation processes required by this Final Rule. Rather, it remains up to each non-public utility transmission provider whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.[577] We also note in response to National Rural Electric Coops and others that the Commission is not proposing any changes to the reciprocity provision of the *pro forma* OATT or any other document. The Commission is not modifying the scope of the reciprocity provision.

817. We disagree with Colorado Independent Energy Association that the Commission should impose any requirements on non-public utility transmission providers for the purpose of avoiding recourse to section 211A, as we do not see any necessity, at this time, to invoke our authority under that

[577] For this same reason, we find that it is not necessary to address Anbaric and PowerBridge's suggestion that this Final Rule should apply to all transmission providers, including those subject to the Commission's reciprocity provisions and enforced as necessary. However, we reiterate our determination in section IV.E.2. that an entity participating in the regional transmission planning process can be identified as the beneficiary of a regional transmission facility and allocated associated costs, irrespective of its status as a public utility under the FPA.

section. In addition, we disagree with MidAmerican, NextEra, and SPP that we should establish requirements regarding participation by non-public utility transmission providers in regional and interregional transmission planning and cost allocation processes beyond those required by reciprocity. We likewise disagree with Western Grid Group that we need to clarify for non-public utility transmission providers the importance of their participation in the processes established by this Final Rule.

818. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public and non-public utility transmission providers. In the Proposed Rule, the Commission described the significance of its proposal for non-public utility transmission providers in terms of the principle of reciprocity.[578] None of the commenters has provided a persuasive reason for departing from the position taken in the Proposed Rule. Thus, as noted above, and consistent with the approach taken in Order No. 890, the Commission expects all public utility and non-public utility transmission providers to participate in the transmission planning and cost allocation processes set forth in this Final Rule. The success of the reforms implemented here will be enhanced if all transmission owners participate. Further, we believe that non-public utility transmission providers will benefit greatly from the improved transmission planning and cost allocation processes required for public utility transmission providers because a well-planned grid is more reliable and provides more available, less congested paths for the transmission of electric power in interstate commerce. Those that take advantage of open access, including improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.

819. In response to G&T Cooperatives and others, we note that the Commission is not acting here under the FPA to require non-public utility transmission providers to participate in regional transmission planning processes or to agree to a method or methods for allocating the costs of their transmission facilities. Under the reciprocity provision, if a public utility transmission provider seeks transmission service from a non-public utility transmission provider to which it provides open access transmission service, the non-public utility transmission provider that owns, controls or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system.[579] A non-public utility transmission provider that elects to receive such service, therefore, must do so on terms that satisfy the reciprocity condition. We disagree that we are using the principle of reciprocity to expand our jurisdiction over non-public utility transmission providers. Non-public utility transmission providers are free to decide whether they will seek transmission service that is subject to the Commission's jurisdiction, and we do not exercise jurisdiction over them when we determine the terms under which public utility transmission providers must provide that transmission service.

820. While a number of commenters argue that this Final Rule's reforms could conflict with their statutory obligations, no specific conflict has been presented for us to act on in this Final Rule. Concerns about possible conflicts should be raised in transmission cost allocation discussions and any subsequent Commission proceedings on proposed transmission cost allocation methods.

821. We disagree with National Rural Electric Coops that our discussion of FPA section 211A in the Proposed Rule is unclear or ambiguous. However, in response to National Rural Electric Coops we note that our intent is to invoke section 211A only on a case-by-case basis. We see no reason to reconsider our position on section 211A as Sacramento Municipal Utility District requests, nor a need to address additional arguments concerning the scope of our authority under section 211A given that we are not acting under section 211A in issuing this Final Rule. Likewise, in response to Georgia Transmission Cooperative, we do not need to provide evidence in this proceeding to support the application of FPA section 211A because we are not applying it here.

822. With regard to Transmission Agency of Northern California's suggestion that an explicit requirement that non-public utility transmission providers comply with the Proposed Rule is unnecessary because they are already complying, we note that this Final Rule does not include any such explicit requirement and instead only notes an expectation that non-public utility transmission providers will participate voluntarily.

VI. Information Collection Statement

823. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[580] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

824. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[581] In the Proposed Rule, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission also included a chart that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements. The Commission received one comment from Arizona Public Service Company specifically addressing the Commission burden estimate in the Proposed Rule.

825. Arizona Public Service Company states that while it supports the need for a robust regional transmission planning process, it contends that the burden estimate in the Proposed Rule understated the number of hours and the average rates of the employees working on these processes. As an example, Arizona Public Service Company states that it participates in WestConnect, which in the past twelve months has involved over two dozen regional or subregional transmission planning meetings. According to Arizona Public Service Company, many of these meetings last an entire day, and require a significant amount of preparation work prior to the meeting. It further contends that the Commission should have included calculation of travel expenses of participants in the regional transmission planning

[578] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 43.

[579] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[580] 5 CFR 1320.11(b).

[581] 44 U.S.C. 3507(d).

processes, including transportation, lodging, and meal expenses.

826. In the Proposed Rule, the Commission estimated the number of hours required for the average public utility transmission provider to comply with the minimum requirements included in the Proposed Rule. The burden estimates in this Final Rule represent the incremental burden changes related only to the requirements set forth in this Final Rule.[582] It should also be noted that the burden estimates are averages for all of the filers. Furthermore, we acknowledge that some regional transmission planning processes have been developed to date that may require more time to participate than the estimate that the Commission provided in the Proposed Rule. However, the fact that such processes have been developed reflects the choice of the participants in those regional transmission planning processes on how to comply with the Commission's rules, it does not mean that the Commission's rules necessarily required such processes. For example, we note that public utility transmission providers may decide, in a particular region or between regions, to develop a regional transmission planning process that includes more objectives and procedures than the minimum set forth in this Final Rule, which may increase the number of hours necessary to participate. In any event, Arizona Public Service Company did not provide any estimates of the number of hours that it has taken to participate in its regional transmission planning processes, nor suggested alternative estimates. Thus, for the most part, the Commission adopts the burden estimates that it set out in the Proposed Rule.

827. As for the hourly rates of the employees, the Commission relies on average national salaries to develop hourly rates of the employees necessary to comply with the requirements adopted in this Final Rule. Again, we note that this is an average rate, and that rates may be higher or lower depending on the area of the country where the public utility transmission provider is located. Therefore, we find that the averages in the Proposed Rule are reasonable estimates of the average national rates for the employees described below.

828. Finally, the Commission has included, in its burden estimate, the number of hours that a public utility transmission provider may need to travel to participate in a regional transmission planning process and interregional transmission coordination procedures.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in this Final Rule follow.

FERC–917—Proposed reporting requirements in RM10–23	Annual number of respondents (filers)	Annual number of responses	Hours per response	Total annual hours in year 1	Total annual hours in subsequent years
Participation in a transparent and open regional transmission planning process that meets regional transmission planning principles, includes consideration of transmission needs driven by Public Policy Requirements, identifies and evaluates transmission facilities to meet needs, develops cost allocation method(s), and produces a regional transmission plan that describes and incorporates a cost allocation method(s) that meets the Commission's principles.	132	132	110 hrs in Year 1; 52 hrs in subsequent years.	14520	6864
Development of interregional transmission coordination procedures that meet the Commission's requirements, including the ongoing requirement to provide or post certain transmission planning information and provide annual data exchange, as well as the development of a cost allocation method for interregional transmission facilities that meets the Commission's principles.	132	132	133 hrs in Year 1; 43 hrs in subsequent years.	17556	5676
Conforming tariff changes for local transmission planning, including those related to consideration of transmission needs driven by Public Policy Requirements; and conforming tariff changes for regional transmission planning and interregional transmission coordination.	132	132	57 hrs in Year 1; 25 hrs in subsequent years.	7524	33000
Total Estimated Additional Burden Hours, Proposed for FERC–917 in NOPR in RM10–23.	....	....	....	39600	15840

Cost to Comply

Year 1: $4,514,400 or [39,600 hours × $114 per hour[583]]

Subsequent Years: $1,805,760 or [15,840 hours × $114 per hour]

Title: FERC–917.

Action: Proposed Collections.

OMB Control No: 1902–0233.

Respondents: Public Utility Transmission Providers. An RTO or ISO also may file some materials on behalf of its members.

Frequency of Responses: Initial filing and subsequent filings.

Necessity of the Information

829. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission adopts these amendments to the *pro forma* OATT to correct certain deficiencies in the transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this Final Rule is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just

[582] 5 CFR 1320.3(b)(1)–(2).

[583] The estimated cost of $114 an hour is the average of the hourly costs of: attorney ($200), consultant ($150), technical ($80), and administrative support ($25).

and reasonable and not unduly discriminatory or preferential. We expect to achieve this goal through this Final Rule by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

830. Interested persons may obtain information on reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: *Data Clearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the 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, phone: (202) 395–4638, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include OMB Control No. 1902–0233 and Docket No. RM10–23–000.

VII. Environmental Analysis

831. 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.[584] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule because section 380.4(a)(15) of the Commission's regulations provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to 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.[585] The reforms herein do not require transmission or other facilities to be built, but rather establish transmission planning mechanisms that will result in a more appropriate allocation of costs and thus better ensure just and reasonable and not unduly discriminatory or preferential rates.

[584] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[585] 18 CFR 380.4(a)(15).

VIII. Regulatory Flexibility Act Analysis

832. The Regulatory Flexibility Act of 1980 (RFA) [586] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890. The total number of public utility transmission providers that, absent waiver, must modify their current OATTs by filing the revised *pro forma* OATT is 132. Of these public utility transmission providers, only 9 filers, or 6.8 percent, have output of four million MWh or less per year.[587] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to request waiver of these requirements. The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

IX. Document Availability

833. 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*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

834. 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.

[586] 5 U.S.C. 601–612.

[587] A firm is ''small'' if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt-hours. Based on the filers of the annual FERC Form 1 and Form 1–F, as well as the number of companies that have obtained waivers, we estimate that 6.8 percent of the filers are ''small.''

835. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

X. Effective Date and Congressional Notification

836. These regulations are effective October 11, 2011. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit this Final Rule to both houses of Congress and the Government Accountability Office.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission. Commissioner Moeller is dissenting, in part, with a separate statement attached.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

■ 2. Amend § 35.28 as follows:
■ a. Paragraphs (c)(1) through (c)(1)(iii) are revised.
■ b. Paragraph (c)(1)(vi) is revised.
■ c. Paragraphs (c)(3), (c)(3)(i), and (c)(3)(ii) are revised.
■ d. Paragraphs (c)(4) through (c)(4)(ii) are revised.
■ e. Paragraph (d)(1) is revised.
■ f. Paragraph (e)(1) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services,

including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms) and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306, Order No. 890, FERC Stats. & Regs. ¶ 32,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of October 11, 2011, it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of October 11, 2011, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

* * * * *

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs. ¶ 31,323, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before October 11, 2011, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff consistent with Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. 1000, FERC Stats. & Regs. ¶ 31,323, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. 1000, FERC Stats. & Regs. ¶ 31,323, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Order No. 1000, FERC Stats. & Regs ¶ 31,323.

(d) * * *

(1) No later than October 11, 2011, or

* * * * *

(e) * * *

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

APPENDIX A—SUMMARY OF COMPLIANCE FILING REQUIREMENTS

Deadline (months after the effective date of the final rule)	Compliance action	Section of the final rule
12 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include local and regional transmission planning processes that are consistent with the requirements of this Final Rule.	Section III.A.
12 months	Submit revised Attachment K of the *pro forma* OATT and other Commission jurisdictional documents to include a cost allocation method or methods for regional cost allocation consistent with principles of this Final Rule.	Section III.C.
18 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include an interregional transmission coordination procedure or procedures consistent with the requirements of this Final Rule.	Section IV.C.
18 months	Submit revised Attachment K of the *pro forma* OATT and any other Commission jurisdictional documents to include a cost allocation method or methods for interregional cost allocation consistent with the principles of this Final Rule.	Section IV.D.

Appendix B: Abbreviated Names of Commenters

The following two tables contain the abbreviated names of initial and reply commenters that are used in this Final Rule.

INITIAL COMMENTERS

Abbreviation	Initial commenter(s)
26 Public Interest Organizations	Alliance for Clean Energy New York; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Earthjustice; Environment Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; National Audubon Society; Natural Resources Defense Council; Pennsylvania Land Trust Alliance; Nevada Wilderness Project; NW Energy Coalition; Pace Energy and Climate Center; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; and Western Grid Group.
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).
AEP	American Electric Power Service Corporation.
Alabama PSC	Alabama Public Service Commission.
Allegheny Energy Companies	Monongahela Power Company; The Potomac Edison Company; West Penn Power Company; Trans-Allegheny Interstate Line Company; and Allegheny Energy Supply Company, LLC.
ALLETE	ALLETE, Inc.
Alliant Energy	Alliant Energy Corporate Services, Inc.
American Antitrust Institute	American Antitrust Institute.
American Forest & Paper	American Forest & Paper Association.
American Transmission	American Transmission Company LLC.
Anbaric and PowerBridge	Anbaric Holding, LLC; PowerBridge, LLC.
APPA	American Public Power Association.
Arizona Corporation Commission	Arizona Corporation Commission.
Arizona Public Service Company	Arizona Public Service Company.
Atlantic Grid	Atlantic Grid Development, LLC on behalf of Atlantic Wind Connection.
Avista and Puget Sound	Avista Corporation and Puget Sound Energy, Inc.
AWEA	American Wind Energy Association; Wind on the Wires; Renewable Northwest Project; Mid-Atlantic Renewable Energy Coalition; Alliance for Clean Energy, Inc.; Interwest Energy Alliance; RENEW; the Wind Coalition; and Center for Energy Efficiency and Renewable Technologies.
Baltimore Gas & Electric	Baltimore Gas & Electric Company.
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California.
Bonneville Power	Bonneville Power Administration.
Boundless Energy and Sea Breeze	Boundless Energy, LLC and Sea Breeze Pacific Regional Transmission System.
Brattle Group (The)	Peter Fox-Penner; Johannes Pfeifenberger; and Delphine Hou.
California Commissions	California Public Utilities Commission and the Energy Resources Conservation and Development Commission of the State of California.
California ISO	California Independent System Operator Corporation.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
California Municipal Utilities	California Municipal Utilities Association (Cities of Alameda; Anaheim; Azusa; Banning; Burbank; Cerritos; Colton; Corona; Glendale; Gridley; Healdsburg; Hercules; Lodi; Lompoc; Moreno Valley; Needles; Palo Alto; Pasadena; Pittsburg; Rancho Cucamonga; Redding; Riverside; Roseville; Santa Clara; Shasta Lake; Ukiah; and Vernon; the Imperial; Merced; Modesto; Turlock Irrigation Districts; the Northern California Power Agency; Southern California Public Power Authority; Transmission Agency of Northern California; Lassen Municipal Utility District; Power and Water Resources Pooling Authority; Sacramento Municipal Utility District; the Trinity and Truckee Donner Public Utility Districts; the Metropolitan Water District of Southern California; and the City and County of San Francisco, and Hetch-Hetchy).
California Transmission Planning Group	Sacramento Municipal Utility District; the Imperial Irrigation District; the Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company and the San Diego Gas & Electric Company.
California State Water Project	California Department of Water Resources State Water Project.
CapX2020 Utilities	Central Minnesota Municipal Power Agency; Dairyland Power Cooperative; Great River Energy; Minnesota Power; Minnkota Power Cooperative; Missouri River Energy Services; Otter Tail Power Company; Rochester Public Utilities; Southern Minnesota Municipal Power Agency; WPPI Energy; and Xcel Energy Inc.
Champlain Hudson	Champlain Hudson Power Express, Inc.
City and County of San Francisco	City and County of San Francisco.
City of Los Angeles Department of Water and Power.	City of Los Angeles Department of Water and Power.
City of Santa Clara	City of Santa Clara, California.
Clean Energy Group	Clean Energy Group.
Clean Line	Clean Line Energy Partners LLC.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company.
Colorado Independent Energy Association	Colorado Independent Energy Association.
ColumbiaGrid	ColumbiaGrid (Avista Corporation; Bonneville Power Administration; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 1 of Snohomish County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; City of Tacoma, Department of Public Utilities, Light Division; and the City of Seattle, by and through its City Light Department).
Connecticut & Rhode Island Commissions	Connecticut Department of Public Utility Control and the Rhode Island Public Utilities Commission.
Conservation Law Foundation	Conservation Law Foundation.
Consolidated Edison and Orange & Rockland	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
Consumers Energy Company	Consumers Energy Company.
Dayton Power and Light	Dayton Power and Light Company (The).
DC Energy	DC Energy, LLC.
Delaware PSC	Delaware Public Service Commission.
Direct Energy	Direct Energy Services, LLC; Direct Energy Business, LLC; and Energy America, LLC.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
Duquesne Light Company	Duquesne Light Company.
EARTHJUSTICE	EARTHJUSTICE.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative.
Eastern Massachusetts Consumer-Owned System.	Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Hingham Municipal Lighting Plant; Reading Municipal Light Department; Taunton Municipal Lighting Plant; and Wellesley Municipal Light Plant.
Edison Electric Institute	Edison Electric Institute.
EIF Management	EIF Management, LLC.
Electricity Consumers Resource Council and the Associated Industrial Groups.	Electricity Consumers Resource Council; American Chemistry Council; Association of Businesses Advocating Tariff Equity; Carolina Utility Customers Association; Coalition of Midwest Transmission Customers; Florida Industrial Power Users Group; Georgia Industrial Group-Electric; Industrial Energy Users—Ohio; Oklahoma Industrial Energy Consumers; PJM Industrial Customer Coalition; West Virginia Energy Users Group; and Wisconsin Industrial Energy Group.
Enbridge	Enbridge Inc.
Energy Consulting Group	Energy Consulting Group LLC (representing Central Georgia EMC; Cobb EMC; Diverse Power Incorporated; Pataula EMC; Snapping Shoals EMC; Upson EMC; and Washington EMC).
Energy Future Coalition Group	Energy Future Coalition; Alliance for Clean Energy New York, Inc.; American Wind Energy Association; BrightSource Energy, Center for American Progress, Conservation Law Foundation; Environmental Northeast; Fresh Energy; Interwest Energy Alliance; Invenergy Thermal Development, LLC; Invenergy Wind Development, LLC; ITC Holdings, Corp.; Mesa Power Group; Mid-Atlantic Renewable Energy Coalition; Natural Resources Defense Council; Renewable Northwest Project; Sierra Club; Solar Energy Industries Association; The FERC Project; The Stella Group, Ltd.; The Wilderness Society; Union of Concerned Scientists; Utility Workers Union of America; and Western Grid Group.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Environmental Defense Fund	Environmental Defense Fund.
Environmental NGOs	Environmental Non-Governmental Organizations (Environmental Integrity Project; Izaak Walton League of America; Clean Air Council; Michigan Environmental Council; Ohio Citizen Action; Natural Resources Defense Council; Fresh Energy; Citizens for Pennsylvania's Future; Sierra Club; and Earthjustice).
E.ON	E.ON U.S. LLC.
E.ON Climate & Renewables North America	E.ON Climate & Renewables North America, LLC.
Exelon	Exelon Corporation.
Federal Trade Commission	Federal Trade Commission.
First Wind	First Wind Energy, L.L.C.
FirstEnergy Service Company	FirstEnergy Service Company, on behalf of FirstEnergy Companies: Ohio Edison Company; Pennsylvania Power Company; The Cleveland Electric Illuminating Company; The Toledo Edison Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; and Pennsylvania Electric Company, and FirstEnergy Solutions Corp. and their respective electric utility subsidiaries and affiliates.
Florida PSC	Florida Public Service Commission.
Four G&T Cooperatives	Associated Electric Cooperative; Basin Electric Power Cooperative; and Tri-State Generation and Transmission Association.
Gaelectric North America	Gaelectric North America.
Georgia Transmission Corporation	Georgia Transmission Corporation.
Governors of Delaware and Maryland	Governors of Delaware and Maryland.
Grasslands	Grasslands Renewable Energy LLC.
Green Energy and 21st Century	Green Energy Express LLC and 21st Century Transmission Holdings, LLC.
Grid Solar	Grid Solar, LLC.
Horizon Wind Energy	Horizon Wind Energy LLC.
Iberdrola Renewables	Iberdrola Renewables, Inc.
Ignacio Perez-Arriaga	Ignacio J. Perez-Arriaga.
Illinios Commerce Commission	Illinois Commerce Commission.
Imperial Irrigation District	Imperial Irrigation District.
Independent Energy Producers Association	Independent Energy Producers Association.
Indianapolis Power & Light	Indianapolis Power & Light Company.
Indicated PJM Transmission Owners	Monongahela Power Company; The Potomac Edison Company and West Penn Power Company; and Trans-Allegheny Interstate Line Company; Baltimore Gas and Electric Company; The Dayton Power and Light Company; Duquesne Light Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; Pennsylvania Electric Company; Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; Atlantic City Electric Company; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC; UGI Utilities, Inc.; and Virginia Electric and Power Company.
Integrated Transmission Benefits Model Proponents.	Maine PUC; Maine Office of the Public Advocate; Maine Office of Energy Independence and Security; New Hampshire Public Utilities Commission; Environment Northeast; and Conservation Law Foundation.
Integrys	Wisconsin Public Service Corporation; Upper Peninsula Power Company; and Integrys Energy Services, Inc.
Invenergy	Invenergy Wind Development LLC.
ISO New England	ISO New England Inc.
ISO/RTO Council	California Independent System Operator; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.
Joint Commenters	American Chemistry Council; American Forest & Paper Association; American Public Power Association; California Municipal Utilities Association; California Public Utilities Commission; Electricity Consumers Resource Council; Indiana Utility Regulatory Commission; Modesto Irrigation District; Montana Public Service Commission; National Association of State Utility Consumer Advocates; New England Conference of Public Utility Commissioners; New Hampshire Office of Consumer Advocate; New Jersey Division of Rate Counsel; New York State Public Service Commission; Office of the Nevada Attorney General, Bureau of Consumer Protection; Old Dominion Electric Cooperative; Sacramento Municipal Utility District; South Dakota Public Utilities Commission; State of Maine, Office of the Public Advocate; Transmission Agency of Northern California; Utility Reform Network; Vermont Department of Public Service; and Vermont Public Service Board.
Kansas City Power & Light and KCP&L Greater Missouri.	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.
Kansas Corporation Commission	Kansas Corporation Commission.
Land Trust Alliance	Land Trust Alliance.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities.
Long Island Power Authority	Long Island Power Authority.
LS Power	LS Power Transmission, LLC.
Maine PUC	Maine Public Utility Commission.
Maine Utilities	Bangor Hydro Electric Company; Central Maine Power Company; and Maine Public Service.
Massachusetts Departments	Massachusetts Department of Public Utilities and Massachusetts Department of Energy Resources.
Massachusetts Municipal and New Hampshire Electric.	Massachusetts Municipal Wholesale Electric Company and New Hampshire Electric Cooperative, Inc.
Michigan Citizens Against Rate Excess	Michigan Citizens Against Rate Excess.
MidAmerican	MidAmerican Energy Holdings Company.
MISO	Midwest Independent System Transmission Operator, Inc.
MISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc.
Minnesota PUC and Minnesota Office of Energy Security.	Minnesota Public Utilities Commission and Minnesota Office of Energy Security.
Modesto Irrigation District	Modesto Irrigation District.
Multiparty Commenters	American Electric Power Corp.; AWEA, Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; and SEIA.
NARUC	National Association of Regulatory Utility Commissioners.
National Audubon Society	National Audubon Society.
National Grid	National Grid USA.
National Rural Electric Coops	National Rural Electric Cooperative Association.
Natural Resources Defense Council	Natural Resources Defense Council.
Nebraska Public Power District	Nebraska Public Power District.
NEPOOL	New England Power Pool Participants Committee.
Nevada Hydro	Nevada Hydro Company.
New England States Committee on Electricity	New England States Committee on Electricity.
New England Transmission Owners	Bangor Hydro Electric Company; Central Maine Power Company; NSTAR Electric Company; New England Power Company; Northeast Utilities Service Company on behalf of the Northeast utilities system operating companies; The United Illuminating Company; and Vermont Electric Transmission Company, Inc., on behalf of itself and its affiliate, Vermont Transco LLC.
New Jersey Board	New Jersey Board of Public Utilities.
New Jersey Division of Rate Counsel	New Jersey Division of Rate Counsel.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
New York Transmission Owners	Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Carolina Agencies	North Carolina Utilities Commission and Public Staff of the North Carolina Utilities Commission.
Northeast Utilities	Northeast Utilities Service Company.
Northern California Power Agency	Northern California Power Agency.
Northern Tier Transmission Group	Northern Tier Transmission Group.
Northwest & Intermountain Power Producers Coalition.	Calpine Corporation; Capital Power Operations; Constellation Energy Control & Dispatch; EverPower Renewables; Exergy Development Group; First Wind; Horizon Wind Energy; Invenergy; LS Power Associates; Ridgeline Energy; Shell Energy North America; TransAlta Marketing, Inc; and TransCanada.
NorthWestern Corporation (Montana)	NorthWestern Corporation (Montana).
NRG Companies	NRG Companies.
NV Energy	Nevada Power Company and Sierra Pacific Power Company.
Ohio Consumers' Counsel and West Virginia Consumer Advocate Division.	Ohio Consumers' Counsel and West Virginia Consumer Advocate Division.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenter(s)
Oklahoma Corporation Commission	Oklahoma Corporation Commission.
Oklahoma Gas and Electric Company	Oklahoma Gas and Electric Company.
Old Dominion	Old Dominion Electric Cooperative.
Omaha Public Power District	Omaha Public Power District.
Organization of MISO States	Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission.
Pacific Gas and Electric Pattern Transmission	Pacific Gas and Electric Company Pattern Transmission LP.
Pennsylvania PUC	Pennsylvania Public Utility Commission.
PHI Companies	Pepco Holdings, Inc.; Potomac Electric Power Company; Delmarva Power & Light Company; and Atlantic City Electric Company.
Pioneer Transmission	Pioneer Transmission, LLC.
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corp.
PPL Companies	PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; and PPL Colstrip II, LLC.
Primary Power	Primary Power, LLC.
PSC of Wisconsin	Public Service Commission of Wisconsin.
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; and PSEG Energy Resources & Trade LLC.
Public Power Council	Public Power Council.
PUC of Nevada	Public Utility Commission of Nevada.
PUC of Ohio	Public Utility Commission of Ohio.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
Salt River Project	Salt River Project Agricultural Improvement and Power District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, CA.
Solar Energy Industries and Large-scale Solar	Solar Energy Industries Association and Large-scale Solar Association.
Sonoran Institute	Sonoran Institute.
South Carolina Electric & Gas	South Carolina Electric & Gas Company.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Southwest Area Transmission Subregional Planning Group.	Southwest Area Transmission Subregional Planning Group.
SPP	Southwest Power Pool, Inc.
Starwood	Starwood Energy Group Global, L.L.C.
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC.
Transmission Access Policy Study Group	Transmission Access Policy Study Group.
Transmission Agency of Northern California	Transmission Agency of Northern California.
Transmission Dependent Utility Systems	Arkansas Electric Cooperative Corporation; Golden Spread Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc.
Tucson Electric	Tucson Electric Power Company.
U.S. Senators Dorgan and Reid	United States Senators Byron Dorgan and Harry Reid.
Vermont Electric	Vermont Electric Power Company, Inc.
Virginia State Corporation Commission	Virginia State Corporation Commission.
Washington Utilities and Transportation Commission.	Washington Utilities and Transportation Commission.
WECC	Western Electricity Coordinating Council.
Westar	Westar Energy, Inc. and Kansas Gas and Electric Company.
WestConnect Planning Parties	Arizona Public Service Company; Basin Electric Power Cooperative; Black Hills Corporation; El Paso Electric Company; Imperial Irrigation District; NV Energy; Public Service Company of New Mexico; Sacramento Municipal Utility District; Salt River Project Agricultural Improvement and Power District; Southwest Transmission Cooperative, Inc.; Transmission Agency of Northern California; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company; and Western Area Power Administration.
Western Area Power Administration	Western Area Power Administration.
Western Grid Group	Western Grid Group.
Western Independent Transmission Group	Western Independent Transmission Group.
The Wilderness Society and Western Resource Advocates.	The Wilderness Society and Western Resource Advocates.
Wind Coalition (The)	Wind Coalition (The).
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.
Wisconsin Electric Power Company	Wisconsin Electric Power Company.
Xcel	Xcel Energy Services Inc.

REPLY COMMENTERS

Abbreviation	Reply commenter(s)
26 Public Interest Organizations	Citizens Utility Board of Wisconsin; Climate and Energy Project; CNT Energy; Conservation Law Foundation; Earth Justice; Energy Conservation Council of Pennsylvania; Energy Future Coalition; Environmental Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Institute for Market Transformation; Iowa Environmental Council; Land Trust Alliance; Midwest Energy Efficiency Alliance; National Audubon Society; Natural Resources Defense Council; Northeast Energy Efficiency Partnerships; NW Energy Coalition; Pace Energy and Climate Center; Pennsylvania Land Trust Association; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; The Wilderness Society; Union of Concerned Scientists; Western Grid Group; Western Resource Advocates; Wind on the Wires.*[588]
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; Louisville Gas & Electric Company and Kentucky Utilities Company; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).*
AEP	American Electric Power Service Corporation.
Alabama Municipal Electric Authority	Alabama Municipal Electric Authority.
APPA	American Public Power Association.
Arizona Public Service Company	Arizona Public Service Company.
Atlantic Grid	Atlantic Grid Development, LLC, on behalf of Atlantic Wind Connection.
Baltimore Gas & Electric	Baltimore Gas and Electric Company.
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; the City of Alameda, California.
Bonneville Power	Bonneville Power Administration.
California ISO	California Independent System Operator Corporation.
California PUC	California Public Utilities Commission.
California Transmission Planning Group	Sacramento Municipal Utility District; the Imperial Irrigation District; the City of Los Angeles Department of Water and Power; the Southern California Public Power Authority; the Transmission Agency of Northern California; the Turlock Irrigation District; the Southern California Edison Company; the Pacific Gas & Electric Company; San Diego Gas & Electric Company.
City of Santa Clara	City of Santa Clara, California.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Northeast Utilities; PPL Corporation; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company; United Illuminating Company.
Commissioner Nathan A. Skop of the Florida PSC.	Commissioner Nathan A. Skop of the Florida PSC.
Conservation Law Foundation	Conservation Law Foundation.
Consolidated Edison and Orange & Rockland	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
EarthJustice and Environmental Groups	EARTHJUSTICE; Environmental Integrity Project; Natural Resources Defense Council; Environmental Law & Policy Center; Fresh Energy.
EarthJustice *et al.*	EARTHJUSTICE on behalf of Sierra Club; Natural Resources Defense Council; National Rural Electric Coops; Citizens for Pennsylvania's Future.
Eastern Environmental and Conservation Groups.	New Jersey Highlands Coalition; New Jersey Chapter of the Sierra Club; Delaware Riverkeeper Network; New Jersey Conservation Foundation; Stop the Lines.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc.; Sam Rayburn G&T Electric Cooperative.
Edison Electric Institute	Edison Electric Institute.
EIF Management	EIF Management, LLC.
Entergy	Entergy Services Inc., on behalf of the Entergy Operating Companies (Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.
Environmental Defense Fund	Environmental Defense Fund.
Exelon	Exelon Corporation.
First Wind	First Wind Energy, L.L.C.
Florida PSC	Florida Public Service Commission.
Green Energy and 21st Century	Green Energy Express LLC and 21st Century Transmission Holdings, LLC.
H–P Energy Resources	H–P Energy Resources LLC.
Identified New England Transmission Owners	Identified New England Transmission Owners.
Illinois Commerce Commission	Illinois Commerce Commission.
ISO New England	ISO New England Inc.
ISO/RTO Council	California Independent System Operator; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; Southwest Power Pool, Inc.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.

REPLY COMMENTERS—Continued

Abbreviation	Reply commenter(s)
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; Tacoma Public Utilities.
LS Power	LS Power Transmission, LLC.
Maine Parties	Maine Public Utilities Commission; Maine Office of the Public Advocate; Maine Governor's Office of Energy, Independence and Security.
MEAG Power	MEAG Power.
MISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); American Transmission Company LLC; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wolverine Power Supply Cooperative, Inc.
Multiparty Commenters	American Electric Power Corp.; AWEA; Energy Future Coalition; Iberdrola Renewables; ITC Holdings Corp.; LS Power Transmission LLC; Mesa Power Group, LLC; NextEra Energy, Inc.; SEIA; and Western Grid Group.*
National Grid	National Grid USA.
National Rural Electric Coops	National Rural Electric Cooperative Association.
New England States Committee on Electricity	New England States Committee on Electricity.
New Jersey Board	New Jersey Board of Public Utilities.
New York Transmission Owners	Central Hudson Gas & Electric; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Dakota and South Dakota Commission	North Dakota Public Service Commission and South Dakota Public Utilities Commission.
Ohio Consumers' Counsel	Office of the Ohio Consumers' Counsel.
Old Dominion	Old Dominion Electric Cooperative.
Organization of MISO States	Illinois Commerce Commission; Indiana Utility Regulatory Commission; Iowa Utilities Board; Michigan Public Service Commission; Minnesota Public Utilities Commission; Missouri Public Service Commission; Montana Public Service Commission; North Dakota Public Service Commission; Public Utilities Commission of Ohio; Pennsylvania Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission.*
Pacific Gas and Electric	Pacific Gas and Electric Company.
Pattern Transmission	Pattern Transmission LP.
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corp.
PPL Companies	PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL RenewableEnergy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; PPL Maine, LLC; PPL Wallingford Energy LLC.*
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Sierra Club	8,203 Sierra Club members, supporters, and electric system ratepayers.
Solar Energy Industries and Large-scale Solar	Solar Energy Industries Association and Large-scale Solar Association.
South Carolina Office of Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Southern New England States	Southern New England States.
Transmission Agency of Northern California	Transmission Agency of Northern California.
Western Independent Transmission Group	Western Independent Transmission Group.
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.

Appendix C: *Pro Forma* Open Access Transmission Tariff

Pro Forma OATT

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent 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 planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

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

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional 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;

(vi) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(vii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(viii) The dispute resolution process;

(ix) The study procedures for economic upgrades to address congestion or the integration of new resources;

(x) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(xi) The relevant cost allocation method or methods.

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

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 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;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated planning process.

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

MOELLER, Commissioner, *dissenting in part*:

While I offer substantial praise for this final rule, the Commission should have taken a different approach to several important issues. But before addressing these issues, we must recognize that all of the nation's difficulties in building needed transmission will not be resolved by this rule. Rather, this rule largely addresses planning for long-distance transmission lines, which is only a subset of the critical issues that are inhibiting needed investment.

[588] A "*" indicates that the composition of this group as altered in the reply comment filing.

This rule cannot address issues like the delays caused by other federal agencies in the siting of important projects, as this Commission lacks the legal authority to require other federal agencies to act.[589] And this rule also cannot address issues of state law, regardless of the reliability needs that are served by a new transmission line. Moreover, and as described further below, this rule did not address whether a transmission provider can thwart competitive options by refusing to upgrade its transmission system. For these reasons, this rule will not resolve all of the difficult issues that discourage this nation from constructing needed transmission lines.

Regarding the issues that the final rule does address, I believe that the owner of a transmission network should have been provided with greater flexibility to ensure the reliability of its own network. Moreover, the rule should have clarified that a right of first refusal is not a right of ''forever'' refusal. That is, a right to ''forever'' block a needed transmission project could prevent the lowest-cost power from reaching consumers.

To encourage needed transmission investment, the final rule permits incumbent transmission owners to maintain their existing rights of first refusal for: (1) local projects where the incumbent does not seek to share the costs of those projects; (2) upgrades to existing assets; and (3) projects on existing right of way.[590] However, notably absent from these categories of projects is the right of a utility to build a project within its franchised service territory in order to maintain the reliability of its existing network—regardless of whether the cost of that project is allocated on a regional basis.

In my view, transmission providers should have been entitled under the final rule to maintain their rights of first refusal to build a new transmission facility that is: (1) located entirely within the provider's franchised service territory; and (2) identified by the provider as needed to satisfy NERC reliability standards—even if that facility is selected in a regional transmission plan for purposes of cost allocation. And because a transmission provider would have retained its authority to address reliability issues in its franchised service territory, the final rule would not have needed its blanket waiver of penalties in the event that a competitor fails to fix a reliability issue.[591]

Had we allowed all reliability projects within a franchised service territory to retain a right of first refusal, this Commission would have emphasized its commitment to reliability. An incumbent transmission provider should be responsible for reliability needs in its franchised territory without regard to cost allocation. And by granting a blanket waiver of penalties, the final rule could be placing the Commission in a difficult position if a blackout results in widespread loss of power, and we are unable to assess a penalty.

My approach also would have encouraged transmission owners to seek regional cost allocation for their own local projects as a way of balancing regional costs. Such a balancing of projects could help ensure that all the parts of a region receive benefits that are at least roughly equivalent. Yet under the final rule, local projects that have their costs assigned regionally generally cannot maintain a right of first refusal, thus discouraging transmission owners from seeking regional cost allocation for their local projects. For this reason, instead of encouraging more regional cooperation, the rule could ultimately discourage such cooperation by encouraging more local transmission projects.

In addition to my concerns regarding reliability, this Commission should have clarified that it was willing to protect the energy markets against misuse of the right of first refusal. That is, the Commission should have emphasized that a right of first refusal in a Commission-jurisdictional tariff is not license to effectively block, or endlessly delay building, a project that would efficiently and cost effectively provide significant benefits to a transmission network. While an incumbent utility with a right of first refusal is entitled to have the ability to exercise its initial right to develop a project, if it decides not to construct, the opportunity to construct the project and thus improve the power grid should be available to a non-incumbent developer.

A review of the transmission projects that have been adopted in various regional plans indicates that most projects will be allowed to retain the right of first refusal under the final rule, as most projects involve upgrades to existing assets, or they are built on an existing right of way, or their costs are not allocated to other transmission providers.[592] Thus, given the extensive number of projects that will be allowed to retain a right of first refusal, the Commission should have emphasized that a transmission provider cannot use a Commission-jurisdictional[593] tariff to prevent the lowest-cost power from reaching consumers.

Recognizing that no party to this proceeding asserted that a right of first refusal grants its holder a right to refuse building a project forever, I believe that a federal right of first refusal must be exercised within a reasonable time frame. The record in this case suggests that 90 days is a reasonable time frame for management to make a decision on whether to exercise its right to build a project.[594] While adoption of a 90-day time frame for transmission providers need not have been mandated, the Commission should have encouraged every region to adopt a time frame that

[589] See the comments of PJM at 17, which state that, ''[t]he PJM Board approved the Susquehanna-Roseland 500 kV line in 2007. The Susquehanna-Roseland line was approved by the state regulatory commissions in Pennsylvania and New Jersey for 2012. The line is currently delayed by the National Parks Service [sic] and is not expected to be in service until 2014 at the earliest.''

[590] Section III.B.3.d of the final rule, at PP 318–319.

[591] For a description of the blanket waiver, see section III.B.4.b of the final rule, at P 344 (''Provided the public utility transmission provider follows the NERC approved mitigation plan, the Commission will not subject that public utility transmission provider to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.'')

[592] For a list of transmission projects that have been approved in PJM, see the various plans for PJM, and a comprehensive list available at: *http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx*. And see Chapter 8 of CAISO's transmission plan for 2010–2011 dated May 18, 2011, available at: *http://www.caiso.com/Documents/Board-approvedISO2010-2011 TransmissionPlan.pdf*.

[593] Consistent with the remainder of the rule, any time limitation on a right of first refusal under my approach would be subject to relevant state and other law concerning property rights, contracts, utility franchises, zoning, siting, permitting, easements, or rights of way. *See* section III.B.2.c of the final rule, at P 287.

[594] Comments of Southwest Power Pool at 14–27; AEP Comments at 3, 19; Comments of Edison Electric Institute at 46–47, Comments of Iberdrola Renewables at 23–24; Comments of Indianapolis Power & Light at 32; MidAmerican Comments at 24; Comments of MISO Transmission Owners at 73; Comments of Oklahoma Gas and Electric Co., at 1, 12, 25; SCE Comments at 41–43; PSEG Reply Comments at 12; Westar Comments at 6; Comments of ITC Companies at 4, 22; Comments of CapX2020 Utilities at 11, where the CapX2020 Utilities consist of Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Co., Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy Inc. In contrast to these comments on a 90-day time limit, LS Power and NextEra object to any right of first refusal and state that a 90-day limitation does not resolve their objections. LS Power Comments at 14–18 and fn. 20; LS Power Reply Comments at 10, 34–35; and NextEra Comments at 16.

best reflects the needs and circumstances of that region.[595]

In conclusion, new transmission lines can sometimes be the lowest-cost way to improve the delivery of electricity. By building needed transmission, our nation's transmission network can be maintained at reliability levels that are the envy of the world, while simultaneously improving consumer access to lower-cost power generation. Plus, a well-designed transmission network can allow efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power. While this rule moves us forward to achieve those goals, a different approach would have been better on the issues described above.

Philip D. Moeller

Commissioner

[595] For example, in the case of the SPP region, the regional transmission organization will designate another company to build a project if the incumbent decides not to build within 90 days. Comments of Southwest Power Pool at 14–27.

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