DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–23–000]

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

Issued June 17, 2010.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing to amend the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. With respect to transmission planning, the proposed rule would provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by State or Federal laws or regulations; improve coordination between neighboring transmission planning regions with respect to interregional facilities; and remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved tariff or agreement, receive different treatment in a regional transmission planning process. Further, 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 facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. With respect to cost allocation, the proposed rule would establish a closer link between transmission planning processes and cost allocation and would require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.

DATES: Comments are due August 30, 2010.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- *Agency Web Site: http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

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Notice of Proposed Rulemaking

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Notice of Proposed Rulemaking

Issued June 17, 2010.

I. Introduction

1. In this Notice of Proposed Rulemaking (Proposed Rule), the Federal Energy Regulatory Commission (Commission) is proposing to reform its electric transmission planning and cost allocation requirements for public utility transmission providers. The proposed 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.

2. This Proposed Rule builds on Order No. 890,[1] in which the Commission reformed the *pro forma* open access transmission tariff (OATT). Among other changes, Order No. 890 required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. Order No. 890 also established nine transmission planning principles, one of which addressed cost allocation for new projects.

3. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The reforms proposed herein seek to build on this progress by improving the effectiveness of regional transmission planning and the efficiency of resulting transmission development. In formulating this proposal, the Commission has sought to balance competing interests and identify a package of reforms that, if implemented, would support the development of transmission facilities identified by the region as necessary to satisfy reliability standards, reduce congestion, and enable compliance with public policy requirements established by State or Federal laws or regulations. The Commission recognizes that opinions may differ as to whether the proposal as formulated will best achieve the Commission's goals. The Commission therefore seeks comment on the reforms proposed herein and encourages commenters to identify enhancements to the reforms that could better support the efficient and effective development of transmission facilities.

4. With respect to transmission planning, the reforms proposed in this Proposed Rule would provide that: (1) Local and regional transmission planning processes account for transmission needs driven by public policy requirements established by State or Federal laws or regulations; (2) coordination between neighboring transmission planning regions is improved with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; and (3) a right of first refusal that is created by a document subject to the Commission's jurisdiction and that provides an incumbent utility with an undue advantage over nonincumbent transmission project developers is removed from that document. 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. Further, 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 facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission preliminarily finds that these proposed reforms are needed to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

5. With respect to transmission cost allocation, the Commission is proposing to require public utility transmission providers to establish a closer link between cost allocation and regional transmission planning processes in which the beneficiaries of new transmission facilities are identified, as well as to establish principles that cost allocation methods must satisfy. The Commission sees these proposals as steps that would increase the likelihood that facilities included in regional transmission plans are actually constructed. For example, establishing a closer link between transmission planning and cost allocation processes would diminish the likelihood that a transmission facility would be included in a regional transmission plan, only to later encounter cost allocation disputes that inhibit construction of that facility.

II. Background

A. Order Nos. 888 and 890

6. In Order No. 888,[2] 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 on a basis that is inferior to that which they provide to themselves.[3] 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.

7. 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.[4] The *pro forma* OATT also required that new facilities be constructed to meet the service requests of long-term firm point-to-point

[1] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[2] *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, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 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 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[3] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682.

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

customers.[5] 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.[6]

8. 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.

9. 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 customers and other 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.[7]

10. The transmission planning reforms adopted in Order No. 890 apply to all public utility transmission providers, including Commission-approved regional transmission organizations (RTOs) and independent system operators (ISOs). The Commission also stated that it expected all non-public utility transmission providers to participate in the planning processes required by Order No. 890. The Commission noted 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 jurisdictional transmission providers.[8] 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.[9] The Commission instead stated that if it found on the appropriate record that non-public utility transmission providers are not participating in the planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

11. 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 planning processes.[10] 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 December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning processes to satisfy the nine transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

12. As a result of these compliance filings, RTOs and ISOs have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions have also made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional transmission planning processes.[11] These improvements to transmission planning processes have given customers and other stakeholders the opportunity to participate in the identification of regional needs and corresponding solutions, thereby facilitating the development of more efficient and effective transmission expansion plans.

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

13. 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.

14. 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 interconnection-wide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing 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

[5] *See* Sections 13.5, 15.4, & 27 of the *pro forma* OATT.

[6] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,311.

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

[8] *Id.* P 441.

[9] 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 (2006).

[10] A small number of transmission providers were granted extensions.

[11] 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.

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.

15. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments.[12] The October 2009 Notice presented numerous questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission.

16. In response to the October 2009 Notice, the Commission received 107 initial comments and 45 reply comments.[13] Many of these comments are discussed in greater detail later in this Proposed Rule, in the context of the Commission's proposals on specific issues.

17. In general, some commenters oppose additional Commission action at this time with respect to transmission planning. Among these commenters, some argue that existing transmission planning processes are adequate to achieve the Commission's stated goals.[14] Some of these commenters highlight work already underway in their own transmission planning regions, arguing that no Commission action is needed at least in those regions. Other commenters argue that existing processes are new or are being revised and should be given time to mature before additional changes are proposed. Many of these commenters state that if the Commission chooses to act, it should do so in a manner that does not disrupt existing transmission planning processes. Some commenters that oppose Commission action on transmission planning at this time state that it is important to maintain what they describe as a "bottom-up" approach to transmission planning, in which regional transmission planning is based on transmission planning conducted by the individual transmission-owning utilities in a transmission planning region.[15]

18. Many other commenters support additional Commission action on transmission planning at this time.[16] These commenters offer a wide range of views on why and how the planning process should be improved. Although these commenters express diverse views, there appears to be a consensus among those supporting action that the Commission should—at a minimum—provide guidance about planning for large, interregional transmission projects.

19. Many commenters that support Commission action on transmission planning raise issues related to the procedural characteristics or geographic scope of existing transmission planning processes. Some commenters contend that the Order No. 890 transmission planning principles should be extended to support interregional coordination, while others argue that additional planning principles are necessary to ensure the effectiveness of transmission planning processes. Some commenters suggest that the type of "bottom-up" transmission planning described above is insufficient,[17] and other commenters advocate changes such as establishing a regional or interconnection-wide planning coordinator.[18] A few commenters suggest that the Commission add to the OATT a *pro forma* seams agreement that includes joint collaborative planning and cost allocation across planning regions.[19] Still other commenters support changes to transmission planning processes, but caution against adopting a one-size-fits-all or an interconnectionwide approach.[20]

20. Other commenters that support Commission action on transmission planning argue that some existing transmission planning processes provide an incumbent transmission owner with an unfair advantage over merchant and independent transmission project developers, such as by providing an incumbent transmission owner with a right of first refusal[21] to construct a transmission facility that is included in a regional transmission plan and meets certain other criteria.[22] These commenters argue that such practices discourage other, merchant and independent transmission developers'[23] participation in the transmission planning process and present a significant barrier to transmission investment. Other commenters state that projects proposed by merchant and independent transmission project developers need to be included fully in regional transmission planning processes on the same basis as other projects.[24]

21. Still other commenters that support Commission action on transmission planning express concern that current transmission planning processes do not adequately assess all of the potential benefits associated with transmission project proposals.[25] Some of these commenters state that more attention needs to be devoted to analyzing the benefits associated with economic-based projects and incorporating such projects into regional transmission plans.[26] PJM states that generic planning principles are needed to deal with the various social, environmental and economic impacts of regional transmission projects. In addition, several commenters recommend that the Commission incorporate State and Federal public policy objectives into the transmission planning process,[27] noting, for example, that doing so could facilitate cost-effective achievement of those objectives. Commenters also

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

[13] *See* Appendix A for a list of the commenters and their abbreviated names.

[14] *E.g.,* Dominion, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, and WECC.

[15] *E.g.,* Ohio Commission, PPL, Southern Companies, and WECC.

[16] *E.g.,* American Transmission, CAlifornians for Renewable Energy, Dayton Power and Light, E.ON, LS Power, NRG, Pioneer Transmission, San Diego Gas & Electric, and Transmission Access Policy Study Group.

[17] *E.g.,* Calvin Daniels (commenting as an individual).

[18] *E.g.,* AEP.

[19] *E.g.,* Midwest ISO Transmission Owners, National Rural Electric Coops, and SPP.

[20] *E.g.,* Pacific Gas and Electric and Transmission Agency of Northern California.

[21] A right of first refusal is defined, for the purposes of this proposed rulemaking, as the right of an incumbent transmission owner to construct, own, and propose cost recovery for any new transmission project that is: (1) Located within its service territory; and (2) approved for inclusion in a transmission plan developed through the Order No. 890 planning process.

[22] *E.g.,* AWEA, EPSA, LS Power, and Transmission Dependent Utility Systems.

[23] 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. For purposes of this proposed rulemaking, an incumbent transmission developer is an entity that develops a project within its own service territory. We note that a transmission owner that proposes a project outside of its own service territory is not considered an incumbent for purposes of that project.

[24] *E.g.,* Allegheny Companies, AEP, CAlifornians for Renewable Energy, Delaware Municipal and Southwestern Electric, E.ON Climate & Renewables North America, Great River Energy, Sun Flower and Mid-Kansas, National Nuclear Security Administration Service Center, Organization of MISO States, and Transmission Agency of Northern California.

[25] *E.g.,* AEP, AWEA, Baltimore Gas and Electric, Energy Future Coalition, Exelon, Green Energy Express, ITC Holdings, MidAmerican, National Audubon Society, *et al.,* NextEra, and Public Interest Organizations & Renewable Energy Groups.

[26] *E.g.,* MidAmerican and Old Dominion.

[27] *E.g.,* AWEA, Baltimore Gas and Electric, Exelon, Eastern PJM Governors, The Brattle Group, ITC Holdings, LS Power, National Audubon Society, *et al.,* National Grid, NextEra, Old Dominion, PJM, Public Interest Organizations & Renewable Energy Groups, Renewable Energy Systems Americas, and Trans-Elect.

recommend that the Commission provide for flexibility so that each transmission planning region could determine which resources it would use to fulfill these public policy objectives.[28]

22. The Commission's questions in the October 2009 Notice with respect to allocating the cost of transmission also drew wide-ranging responses. For example, some commenters express concern that the lack of a link between transmission planning and cost allocation procedures may unnecessarily block or delay needed projects.[29] Other commenters support establishing a generic cost allocation method as a backstop that would apply when parties or transmission planning regions cannot agree on a cost allocation method.[30]

23. Some commenters indicate that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.[31] These commenters generally agree that those who share in the benefits of transmission facilities should be responsible for their costs. However, there is not a consensus on how this principle should be implemented, what benefits should be considered for purposes of cost allocation, or how to determine who is a beneficiary.

24. Some commenters urge the Commission to avoid rushing to a one-size-fits-all approach to determining beneficiaries of transmission projects, due to the varying nature of projects and benefits.[32] Others express the view that it is difficult to quantify certain benefits that they consider relevant, such as carbon emission reduction, integration of renewable generation, or the most efficient use of existing rights-of-way.[33] Other commenters suggest that there are ways to factor difficult to quantify benefits into the planning process such that they are adequately considered.[34]

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: (1) Improve coordination between electric industry participants and states on the regional, interregional, and interconnection-wide levels with regard to long-term electricity policy and planning; (2) 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; (3) increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and (4) facilitate and accelerate development of renewable or other low-carbon generation resources.[35]

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 and stakeholders within each interconnection to guide the analyses and planning performed under Topic A.[36] 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. DOE has also been involved in the development of several recent reports that may have implications for transmission planning. In its 2008 report, *20% Wind Energy by 2030,* DOE concludes that "[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario. Expanded transmission will increase reliability, reduce costly congestion and line losses, and supply access to low-cost remote resources, including renewables." [37]

29. Similarly, in its 2009 report, *Keeping the Lights On in a New World,* the DOE Electricity Advisory Committee concluded that expanding and strengthening the nation's transmission infrastructure is becoming increasingly important for two reasons: "First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by State-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers." [38]

30. The number of states that have adopted renewable portfolio standard measures, as well as the target levels set in those measures, has continued to increase. Some 30 states and the District of Columbia have now adopted renewable portfolio standard measures. 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.

31. In its role as the Commission-designated Electric Reliability Organization, the North American Electric Reliability Corporation (NERC) concluded that significant transmission expansion will be needed to comply with renewable mandates. Even in the absence of a national renewable portfolio standard, NERC has stated that "an analysis of the past 14 years shows that the siting and construction of transmission lines will need to significantly accelerate to maintain reliability over the coming years." [39] In

[28] *E.g.,* Consolidated Edison, *et al.*

[29] *E.g.,* ITC Holdings, AEP, American Transmission, Green Energy Express, and WIRES.

[30] *E.g.,* American Transmission; National Grid; and NEPOOL Participants.

[31] *E.g.,* APPA, Green Energy Express, ITC Holdings, NEPOOL Participants, NextEra, Ohio Commission, Solar Energy Industries, and Transmission Access Policy Study Group.

[32] *E.g.,* APPA, Bonneville, California ISO, ColumbiaGrid, Consolidated Edison, *et al.,* Dayton Power and Light, EEI, Entergy, Midwest ISO, Southern Companies.

[33] *E.g.,* California ISO, Electricity Consumers Resource Council, MidAmerican, National Grid.

[34] *E.g.,* AWEA, Energy Future Coalition, Entergy, Exelon, ITC Holdings, Integrys, *et al.*

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

[36] *Id.* at 4–8.

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

[38] Electricity Advisory Committee, *Keeping the Lights On in a New World,* at 45 (Jan. 2009). The Electricity Advisory Committee was formed to provide advice to DOE in implementing the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, and in modernizing the nation's electricity delivery infrastructure. The Electricity Advisory Committee includes representatives from industry, academia, and state government.

[39] North American Electric Reliability Corporation, *2009 Long-Term Reliability Assessment: 2009–2018,* October 2009, at 29.

its 2009 assessment of transmission needs, NERC found that if a national renewable portfolio standard of 15 percent were adopted, an additional 40,000 miles of transmission lines would be needed and "transmission would be a key component to accommodating new resources, linking geographically remote generation to demand centers." [40]

III. The Need for Reform

32. The Commission notes that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. As noted above, these improvements have increased opportunities for customers and other stakeholders to participate in the identification of regional needs and corresponding solutions, facilitating the development of more efficient and effective transmission plans. The Commission believes that the expanded cooperation and collaboration that is now occurring in transmission planning both among transmission providers and between transmission providers and their stakeholders is to be commended.

33. Although Order No. 890 became effective just a few years ago, there have been significant changes in the nation's electric power industry in those few years that require the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. These changes have been widely recognized within the industry.[41] Our intention in this Proposed Rule is not to disrupt the progress that is already 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.

34. The siting, permitting, and cost allocation of transmission facilities face significant challenges. These challenges may be present whether an interstate transmission project is proposed to be located within a single region for which transmission planning is conducted in accordance with Order No. 890 (*i.e.,* an intraregional transmission facility) or is instead proposed to be located in more than one such transmission planning region (*i.e.,* an interregional transmission facility). The failure to address these challenges also can lead to increases in congestion costs. For example, PJM stated recently that prices for new generating capacity in the eastern part of its transmission planning region have increased due to constraints on its transmission system. Observing that capacity prices in the western portion of PJM were $27.73 per megawatt-day, while capacity prices in the transmission-constrained areas of PJM were between $226.15 and $247.14 per megawatt-day, PJM noted that "the great difference in prices for the eastern portion of PJM compared with elsewhere shows the need for increased transmission line capacity into the region. Transmission line additions and upgrades would reduce capacity price differences." [42]

35. In light of the comments and developments discussed above, one deficiency that has arisen is the lack of a requirement for a regional transmission plan, without which the construction of new transmission facilities could be inhibited. Additionally, in the absence of such a requirement, the facilities best suited to meet the needs of a particular region may not be identified.

36. Another deficiency that has arisen since the issuance of Order No. 890 involves transmission needs driven by public policy requirements established by State or Federal laws or regulations. For example, State policies to promote increased reliance on renewable energy resources, such as the renewable portfolio standard measures discussed above, accentuate the need for transmission to deliver electricity from location-constrained renewable energy resources to load centers. Other State policies, such as goals for use of energy efficiency or demand response, may lower load forecasts within a given load zone and thereby affect transmission planning determinations. In addition, states may adopt economic development policies associated with meeting energy needs that may be relevant to assumptions made in a transmission planning process. Future public policy requirements established by Federal laws or regulations also could have a significant effect on transmission planning.

37. However, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, these types of public policy requirements established by State or Federal laws or regulations. Indeed, some comments submitted in response to the October 2009 Notice indicate that current transmission planning processes may not permit consideration of public policy requirements within regional transmission plans.[43] As discussed in greater detail below, the Commission preliminarily finds that the failure to account explicitly for such public policy requirements in the transmission planning process may result in undue discrimination and rates, terms, and conditions of service that are not just and reasonable.

38. A third deficiency involves obstacles to nonincumbent transmission project developers' participation in regional transmission planning processes. The Commission in recent years has seen increasing interest in transmission investment among these developers. Such interest, however, often has been coupled with expressions of concern about the treatment of merchant and independent transmission project developers in relevant transmission planning processes.[44] Many commenters raised similar concerns in response to the October 2009 Notice, describing what they see as remaining opportunities for undue discrimination against nonincumbent transmission project developers in transmission planning processes. Such undue discrimination could discourage these developers from presenting projects in regional transmission planning processes, which, in turn, could inhibit development of beneficial transmission facilities.

39. A fourth deficiency involves the relative lack of coordination between transmission planning regions. In Order No. 890, the Commission found that when transmission providers engage in

[40] North American Electric Reliability Corporation, *2009 Scenario Reliability Assessment: 2009–2018,* October 2009, at 9.

[41] For example, a trend of increased investment in the country's transmission infrastructure has emerged in recent years. EEI attributes that trend to, among other factors, recognition of the reliability and other developments discussed above, as well as enactment of the Energy Policy Act of 2005 and the Commission's implementation of its new transmission pricing policies. EEI has also observed that even amid this trend of increased investment in transmission infrastructure, transmission projects that would be located in more than one state "face significant challenges for siting, permitting, cost allocation and cost recovery." *Transmission Projects: At a Glance,* Prepared by Edison Electric Institute with assistance from Navigant Consulting, Inc., February 2010, at iii–iv. EEI has also stated that "[t]hese challenges must be resolved to facilitate the movement of large quantities of renewable energy." *Transmission Projects Supporting Renewable Resources,* Prepared by Edison Electric Institute, February 2009, at iv.

[42] PJM Interchange, News Release, May 14, 2010.

[43] *E.g.,* Baltimore Gas and Electric, Eastern PJM Governors, ITC Holdings, LS Power, National Grid, Old Dominion, PJM, and Trans-Elect.

[44] *See, e.g., Green Energy Express LLC,* 129 FERC ¶ 61,165 (2009); *Western Grid Dev., LLC,* 130 FERC ¶ 61,056 (2010); *Pioneer Transmission LLC,* 126 FERC ¶ 61,281 (2009).

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.[45] Similarly, in the absence of coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility-level and regional transmission planning processes, potentially including interregional transmission projects. In the few years since the issuance of Order No. 890, interest in multiregional facilities has grown significantly.[46] The October 2009 Notice observed that the lack of coordinated planning over the seams of current transmission planning regions could be needlessly increasing costs for customers of individual transmission providers. Accordingly, the Order No. 890 transmission planning requirements may not be just and reasonable in that they may not be sufficient to address the need for greater coordination in interregional transmission planning.

40. Finally, we preliminarily conclude that existing methods for allocating the costs of new transmission may not be just and reasonable because they may inhibit the development of efficient, cost-effective transmission facilities necessary to produce just and reasonable rates. While challenges associated with allocating the cost of transmission are not new, those challenges appear to have become more acute as the need for transmission infrastructure has grown. For example, the expansion of regional power markets and the increasing adoption of State policies to promote increased reliance on renewable energy resources have led to a growing need for regional or interregional transmission facilities. Meanwhile, determining the benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. In such circumstances, any individual beneficiary of a project has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development.

41. Moreover, as stated in the October 2009 Notice, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, there are few rate structures in place today that provide for the allocation and recovery of costs for projects that are proposed to be located either within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region. The lack of such rate structures creates significant risk for transmission project developers that they will have no identified group of customers from which to recover the cost of their investment.

42. Therefore, the Commission proposes to reform transmission planning and cost allocation processes as described in the following sections of this Proposed Rule. Although focused on discrete aspects of the transmission planning and cost allocation processes, these reforms are integrally related and should be understood as a package. With these related reforms, more transmission projects would be considered in the transmission planning process on an equitable basis, and more facilities that are included in transmission plans are likely to move forward to construction.

43. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public utility and non-public utility transmission providers. Consistent with the approach taken in Order No. 890,[47] the Commission expects all public utility and non-public utility transmission providers to participate in the regional transmission planning and cost allocation processes proposed by this Proposed Rule. Reciprocity dictates that non-public utility transmission providers that take advantage of open access, including improved regional transmission planning and cost allocation, should be subject to the same requirements as public utility transmission providers. 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 allows us 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 regional transmission planning and cost allocation processes proposed in this Proposed Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

IV. Proposed Reforms: Transmission Planning

44. Transmission planning is a critical component of the provision of transmission service in interstate commerce. Among other purposes, transmission planning is the means by which the transmission needs of a given area and the facilities that are best suited to meet those needs are identified. Based on the comments received in response to the October 2009 Notice and the other developments and considerations discussed above, the Commission believes that further steps with respect to transmission planning may be necessary to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

A. Participation in the Regional Planning Process

45. In Order No. 890, the Commission adopted a regional participation principle as a necessary component of a public utility transmission provider's transmission planning process. To meet that principle, the Commission required that each public utility transmission provider 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.[48] This requirement for coordination at the regional level can be contrasted with the separate requirement in Order No. 890 that each public utility transmission provider use an open and transparent process to develop a transmission plan for its own control area.[49] In other words, by adopting the regional participation principle, the Commission

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

[46] *See, e.g., Pioneer Transmission LLC,* 126 FERC ¶ 61,281 (2009); *Green Power Express,* 127 FERC ¶ 61,031 (2009).

[47] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 441.

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

[49] *Id.* P 494, 523.

did not require development of a comprehensive regional transmission plan.

46. The Commission explained that in complying with the regional participation principle, the specific features of a public utility transmission provider's regional transmission planning process should take account of and accommodate, where appropriate, existing institutions, as well as historical practices and the physical characteristics of the region.[50] The Commission recognized that regional transmission planning already occurs, for example, as part of the NERC Regional Entity planning process.[51] The Commission urged public utility transmission providers to closely examine whether improvements in these regional transmission planning processes could be implemented to satisfy the requirements of Order No. 890 imposed on individual transmission providers.[52]

47. The Commission also stated that to satisfy the regional participation principle, an existing transmission planning process must be open and inclusive and address both reliability and economic considerations.[53] The Commission required each public utility transmission provider to participate in a transmission planning process that facilitates regional participation and that is open to all interested customers and stakeholders.[54] However, the Commission did not require each regional transmission planning process to comply with each of the nine transmission planning principles established in Order No. 890.[55]

48. On compliance with these Order No. 890 requirements, many public utility transmission providers relied on existing regional entities and transmission planning processes, modified as necessary, to comply with the regional participation principle.[56]

49. Since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890's regional participation principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. Without such a process, each transmission provider will not have information needed to assess proposed projects and determine which project or group of projects could satisfy local and regional needs more efficiently and cost-effectively. As a result, the rates, terms and conditions of transmission services may not be just and reasonable. For example, greater regional coordination in transmission planning would expand opportunities for transmission providers, their transmission customers, and other stakeholders to identify and implement regional solutions to local and regional needs that are more cost-effective than those proposed in the transmission planning process of individual transmission providers. In addition, more effective regional transmission planning could better facilitate the integration of location-constrained renewable energy resources, which may be needed to fulfill public policy requirements such as the renewable portfolio standards adopted by many states.

50. Given this concern, we propose to 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 established in Order No. 890: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.[57]

51. More specifically, we propose to 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 cost-effectively meet the needs of transmission providers, their transmission customers, and other stakeholders.[58] When an individual transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission solutions 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. Likewise, the regional transmission planning process would consider and evaluate transmission facilities and non-transmission solutions that are proposed and develop a regional transmission plan that identifies what transmission facilities are needed to meet the needs of transmission customers and other stakeholders in the region.[59]

52. In addition, because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, transmission customers and other stakeholders must be provided with an opportunity to participate meaningfully in that process. Therefore, we propose to apply the above-noted Order No. 890 transmission planning principles to the regional transmission planning process, which would ensure that transmission customers and other stakeholders can express their needs before a regional transmission plan is finalized and thus help to identify solutions that more efficiently address the region's needs. Similarly, ensuring access to the models and data used in the regional transmission planning process would allow transmission customers and other stakeholders to determine if their needs are being addressed in a cost-effective manner. Greater access to information and transparency would also help transmission customers and other stakeholders to recognize and understand the benefits that they will receive from a transmission facility that is included in a regional transmission plan. This consideration is particularly important in light of our proposal below to require that each public utility transmission provider have a cost allocation method for transmission

[50] *Id.* P 524.

[51] *Id.* P 528.

[52] *Id.* P 526.

[53] *Id.* P 528.

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

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

[56] As we note above, 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 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.

[57] This proposal does not include the regional participation principle and cost allocation for new projects principle of Order No. 890 because we address interregional coordination in transmission planning and cost allocation for transmission facilities included in a regional transmission plan elsewhere in this Proposed Rule.

[58] When evaluating potential solutions to identified needs, transmission providers must evaluate proposals for transmission, generation, and demand resources against one another based on criteria set forth in their tariffs. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494–95; Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 216. The Commission also has recognized that in appropriate circumstances alternative technologies may be eligible for treatment as transmission for ratemaking purposes. *Western Grid,* 130 FERC ¶ 61,056 (2010).

[59] As noted in Order No. 890, the planning obligations proposed here do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with transmission providers. With that said, the Commission fully intends that the transmission planning processes provide for the timely and meaningful input and participation of customers into the development of transmission plans. *Id.* P 454.

facilities included in its regional transmission plan that reflects the benefits that those facilities provide.

53. 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 would be 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 requirements.

54. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule.

B. Public Policy Driven Projects

55. In Order No. 890, the Commission included an Economic Planning Studies principle among the nine transmission planning principles. The Commission stated that its primary objective in adopting that principle was "to ensure that the transmission planning process encompasses more than reliability considerations." [60] The Commission explained that although planning to maintain reliability is a critical priority, transmission planning also involves economic considerations.[61]

56. More specifically, the Commission stated that when conducting transmission planning to serve native load customers, a prudent vertically integrated transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load.[62] The Commission identified this potential for undue discrimination among a transmission provider's customers as a justification to implement the Economic Planning Studies principle requiring transmission providers to make available to their customers services that are comparable to those they are performing on behalf of their native loads.[63]

57. The Economic Planning Studies principle requires that stakeholders be given the right to request a defined number of high priority studies annually through the transmission planning process. As defined in Order No. 890, these high priority studies are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including upgrades to integrate new resources or loads on an aggregated or regional basis.[64]

58. In Order No. 890, the Commission also required each public utility transmission provider to coordinate its transmission planning activities with the relevant State and local regulatory authorities that choose to participate in the transmission planning process and stated its expectation that "all transmission providers will respect states' concerns." [65] As such, State and local regulatory authorities may fully participate in the existing Order No. 890 transmission planning process and identify, among other issues, public policy requirements established by State or Federal laws or regulations that they see as relevant to transmission needs. However, when choosing whether to include a proposed transmission project in its local or regional transmission plan, a public utility transmission provider has no explicit obligation under Order No. 890 or the *pro forma* OATT to evaluate the project based on its potential to facilitate the achievement of public policy requirements established by State or Federal laws or regulations.

59. The October 2009 Notice observed that some areas are struggling with how to adequately address transmission expansion necessary to, for example, integrate renewable generation resources into the transmission system. The October 2009 Notice attributed these difficulties in part to the fact that planning transmission facilities necessary to meet State resource requirements, such as the renewable portfolio standard measures discussed above, 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.[66] Drawing on these observations, the October 2009 Notice sought comment as to whether reliability impact studies are properly aligned with evaluations of economic-based projects or projects proposed to satisfy renewable energy standards. To the extent that assessments of various possible project benefits are not properly aligned, the October 2009 Notice sought comment as to how reliability assessments, economic evaluations and assessments of a project's ability to meet public policy goals could be aligned to better identify options that meet all of these regional needs.[67]

60. The Commission received a number of comments on these issues, expressing a range of opinions. Several commenters argue that the existing transmission planning and stakeholder processes properly align reliability impact studies with evaluations of other projects designed to meet economic-based or public policy requirements.[68] Other commenters suggest that it would be inappropriate for the Commission to require that renewable energy standards be incorporated into the transmission planning process.[69] For example, Public Power Council contends that the Commission lacks jurisdiction to require that the resources necessary to comply with State renewable energy standards are accounted for in the transmission planning process, as such standards are State-level policies.[70]

61. In addition, several commenters recommend that the Commission incorporate public policy objectives into the transmission planning process.[71] For example, PJM argues that "additional guidance from the Commission is needed if public policy imperatives such as aggressive integration of renewable resources are to be met." [72] PJM states that while ensuring system reliability should remain the primary goal of the transmission planning process, providing for incorporation of public policy objectives, where applicable, could facilitate cost-effective achievement of those objectives. In particular, PJM suggests that the Commission move beyond a strict application of "bright line" criteria currently used for reliability and economic projects and allow transmission providers more flexibility

[60] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 542.

[61] *Id.*

[62] The Commission further stated that such upgrades could, for example, reduce congestion (redispatch) costs or integrate efficient new resources (including demand resources) and new or growing loads. *Id.*

[63] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 240.

[64] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547–48.

[65] *Id.* P 574.

[66] October 2009 Notice at 3.

[67] *Id.* at 4.

[68] *E.g.,* Dominion, Entergy, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, Southern Companies, WestConnect Planning Parties, and WECC. In addition, PSEG Companies state that while it is true that reliability impact studies are performed independently of economic planning, such a distinction is appropriate because ensuring reliability is the primary objective of the planning process.

[69] *E.g.,* Massachusetts Departments and Public Power Council.

[70] Massachusetts Departments share a similar concern.

[71] *E.g.,* AWEA, Baltimore Gas and Electric, Public Interest Organizations & Renewable Energy Groups, Exelon, Eastern PJM Governors, ITC Holdings, LS Power, National Grid, NextEra, Old Dominion, PJM, Renewable Energy Systems Americas, Trans-Elect, and The Brattle Group.

[72] PJM Order No. 890 Technical Conference Comments, op. cit. at 6.

to take into account the multiple reliability, economic, or public policy-based benefits a single project may be able to provide.[73]

62. Other commenters propose various approaches to incorporating public policy objectives into the transmission planning process. Some of these commenters argue that if the goal of the transmission planning process is to allow load-serving entities to satisfy their resource needs, such needs could include resources required to comply with State and Federal public policy objectives.[74] Still other commenters recommend that the Commission provide flexibility in the transmission planning process so that each region can determine which resources it will use to fulfill any applicable public policy objectives.[75]

63. 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 Commission preliminarily finds that transmission needs driven by public policy requirements established by State or Federal laws or regulations should be taken into account in the transmission planning process. Indeed, consideration of such public policy requirements raises issues similar to those raised in the Commission's discussion in Order No. 890 of the Economic Planning Studies principle.[76] 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 enable compliance with relevant public policy requirements established by State or Federal laws or regulations in a cost-effective manner. Therefore, we propose to find 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. In addition, providing for incorporation of public policy requirements established by State or Federal laws or regulations in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.

64. To address these issues, we propose to revise the requirements established in Order No. 890 with respect to local and regional transmission planning processes.[77] Specifically, we propose 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 may drive transmission needs. 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. 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 economic studies principle in the transmission planning process.

65. The Commission does not propose to identify the public policy requirements established by State or Federal laws or regulations that must be considered in individual local and regional transmission planning processes. Instead, we propose to require each public utility transmission provider to coordinate with its customers and other stakeholders to identify public policy requirements established by State or Federal laws or regulations that are appropriate to include in its local and regional transmission planning processes.

66. We propose to require each public utility transmission provider to specify in its OATT the procedures and mechanisms in its local and regional transmission planning processes for evaluating transmission projects proposed to achieve public policy requirements established by State or Federal laws or regulations. If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then it must make that demonstration in its compliance filing.

67. This proposed requirement is intended to clarify the objectives that would be considered in local and regional transmission planning processes. As we stated in Order No. 890, we believe that the transparency provided under open transmission planning processes can provide useful information that would help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the State level, and address other factors states wish to consider.

68. Another benefit of this proposed requirement to consider public policy requirements established by State or Federal laws or regulations within the transmission planning process is that adherence with this proposed requirement may eventually increase the proportion of transmission network investment that is constructed pursuant to proactive transmission planning processes, thereby reducing the proportion of network upgrades that would otherwise be triggered by individual generator interconnection requests, which can be time consuming and inefficient. If more of the transmission network were expanded under the type of regional transmission planning process described above, then the network upgrades triggered by interconnection requests should be less significant in size and cost than they have been in the past and the associated differences in cost allocation provisions may become less significant as well.

69. This proposed requirement is not intended in any way to infringe upon State authority with respect to integrated resource planning.[78] In addition, to the extent that a public utility transmission provider has an obligation to comply with public policy requirements established by State or Federal laws or regulations, such as the State renewable portfolio standard measures discussed above, this proposed requirement is not intended to convert a failure to satisfy that obligation into a violation of its OATT. In other words, while a public utility transmission provider would be required to identify and consider public policy requirements established by State or Federal laws or regulations in its local and regional transmission planning processes, this proposed requirement would not establish an

[73] *Citing, PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 (2007) (directing PJM to adopt a formulaic approach to applying metrics used to choose economic projects).

[74] *E.g.,* APPA and Bay Area Municipal Transmission Group.

[75] *E.g.,* Consolidated Edison, et al.

[76] 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 upgrades to integrate new resources and loads on an aggregated or regional basis. The Commission recognizes that its statements with respect to the economic planning studies principle may have contributed to confusion as to whether public policy requirements may be considered in the transmission planning process.

[77] By "local" transmission planning process, we mean the transmission planning process that a pubic utility transmission provider performs for its individual service territory or footprint pursuant to the requirements of Order No. 890.

[78] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479, n.274.

independent obligation to satisfy those requirements.

70. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment as to whether public policy requirements established by State or Federal laws or regulations should be considered in the transmission planning process. Further, we seek comment on how planning criteria based on public policy requirements should be formulated, including whether it is more appropriate to use flexible criteria instead of "bright line" metrics when determining which projects are to be included in the regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a 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 project over successive planning cycles and therefore create inappropriate disruptions in long-term transmission planning.

C. Opportunities for Undue Discrimination Against Nonincumbent Transmission Developers

1. Nonincumbent Transmission Developer Participation in the Transmission Planning Process

71. 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 undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes.

72. The October 2009 Notice observed that in some areas, when a nonincumbent transmission developer participates in the transmission planning process, it may lose the opportunity to construct its proposed project to the incumbent transmission owner if that owner has a right of first refusal to construct any transmission facility in its service territory. The October 2009 Notice also observed that in some areas, merchant transmission developers choose to plan proposed facilities outside of the transmission providers' planning processes.[79]

73. The October 2009 Notice posed several questions relating to merchant and independent transmission developers' participation in the regional transmission planning process. The October 2009 Notice sought comment on how projects proposed by merchant or independent transmission developers should be treated in the regional transmission planning process. The October 2009 Notice also asked whether these types of developers should be required to participate in the regional transmission planning process and, if so, at what point they should be required to engage in that process. In addition, the October 2009 Notice asked whether the 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. Finally, the October 2009 Notice asked whether there are barriers to merchant and independent transmission developers' participation in the regional transmission planning process other than rights of first refusal.[80]

74. These questions generated extensive comments. For example, many commenters argue that a project proposed by a merchant or independent transmission developer should be treated on the same basis as all other proposed projects.[81] Also, a number of commenters assert that merchant and independent developers should be required to participate in the transmission planning process.[82] For example, Southern Companies asserts that it would be discriminatory if the Commission did not require merchant and independent developers to participate in the transmission planning process, as jurisdictional and non-jurisdictional transmission providers are required to do.

75. Other commenters state that merchant and independent developers should not be treated similarly or required to participate in the transmission planning process. For example, Chinook and Zephyr and ITC Holdings state that because the business model of merchant and independent transmission developers is different from that of vertically-integrated utilities, different transmission planning requirements are appropriate for them. Chinook and Zephyr also argue that regional transmission planning requirements should apply to a merchant developer only after it is operating under a Commission-approved OATT. Dayton Power and Light contends that while any transmission facility that is necessary to meet NERC reliability criteria, regardless of ownership, should be required to be included in the transmission planning process, merchant and independent projects planned for nonreliability reasons can be developed independently of the transmission planning process, subject to appropriate interconnection requirements.

76. Other commenters emphasize the importance of allowing merchant and independent developers to participate actively in the transmission planning process.[83] Generally, these commenters argue that merchant and independent transmission developers should either participate in the transmission planning process as early as practical, at the beginning of the transmission planning cycle, or as soon as they have a proposal that is developed well enough to be considered. Pattern Transmission also suggests that the Commission should better define the transmission planning process and the roles of its participants to ensure a level playing field for independent transmission developers.

77. The questions about whether an incumbent transmission owner's right of first refusal unreasonably impedes merchant or independent transmission development and, if so, how this impediment could be addressed, also generated extensive comments. Many commenters state that a right of first refusal does not unreasonably impede merchant and independent transmission development.[84] Various commenters

[79] October 2009 Notice at 3.

[80] *Id.* at 4.

[81] *E.g.,* Allegheny Companies, AEP, CAlifornians for Renewable Energy, Delaware Municipal and Southwestern Electric, E.ON Climate & Renewables North America, Great River Energy, Sun Flower and Mid-Kansas, National Nuclear Security Administration Service Center, Organization of MISO States, and Transmission Agency of Northern California.

[82] *E.g.,* APPA, CAlifornians for Renewable Energy, Delaware Municipal and Southwestern Electric, Dominion, Exelon, Integrys, Old Dominion, Sun Flower and Mid-Kansas, Large Public Power Council, Midwest ISO, National Nuclear Security Administration Service Center, National Rural Electric Coops, New England States' Committee on Electricity, New York PSC, Organization of MISO States, Pacific Gas and Electric, Ohio Commission, SPP, San Diego Gas & Electric, South Carolina Electric & Gas, Transmission Access Policy Study Group, Transmission Agency of Northern California, Transmission Dependent Utility Systems, and Xcel.

[83] *E.g.,* Green Energy Express, ITC Holdings, Pattern Transmission, and Starwood.

[84] *E.g.,* Allegheny Companies, AEP, Ameren, Baltimore Gas and Electric, Dominion, EEI, Great River Energy, Integrys, et al., Sun Flower and Mid-Kansas, Large Public Power Council, MidAmerican, Midwest ISO Transmission Owners, National Grid, Northern Tier Transmission Group, Old Dominion, PPL, PSEG Companies, Ohio Commission, San Diego Gas & Electric, Southern California Edison,

present a range of reasons that it is appropriate for an incumbent transmission provider to have a right of first refusal, including that the incumbent transmission owner: (1) Has a legally enforceable obligation to maintain reliability on its systems and faces penalties for noncompliance; (2) is obligated under State law to provide reliable service at the lowest reasonable cost; (3) may be required to build facilities included in an RTO's or ISO's regional plan, an obligation that merchant and independent transmission developers lack; (4) is best situated to develop transmission facilities within its service territory, as it is most familiar with the design and operation of its system, its customers' needs, and State and local permitting and siting processes; and (5) may be able to provide transmission services at a lower cost than a merchant or independent transmission developer because it enjoys economies of scale with respect to the staff and resources necessary to maintain and operate new transmission facilities.

78. Some commenters contend that the right of first refusal should be preserved because an incumbent transmission owner that voluntarily joined an RTO or ISO did so with the understanding that it would retain the right to invest in and earn a return on new facilities within its system.[85] According to Midwest ISO Transmission Owners, eliminating a right of first refusal could provide a disincentive for RTO membership. Similarly, the California ISO asserts that without a right of first refusal, a transmission owner may have less incentive to participate in an RTO or ISO.

79. However, other commenters argue that a right of first refusal impedes transmission development and provides an undue advantage to an incumbent transmission owner.[86] Such commenters present a number of reasons for eliminating a right of first refusal, including the following: (1) A right of first refusal provides a disincentive for a merchant or independent developer to propose a project, especially a proposal for a transmission facility that spans multiple utilities' service territories, because any investment that it makes in developing a proposal may be lost if an incumbent transmission owner can exercise its right of first refusal or otherwise delay the project or prevent construction of the project; (2) by discouraging competition and new entry, a right of first refusal likely increases costs to ratepayers; and (3) a merchant or independent transmission developer may have difficulty obtaining financing if investors perceive that its proposed project could be subject to a right of first refusal or is otherwise at a disadvantage compared to a project sponsored by an incumbent transmission owner.

80. Among other comments on this issue, Startrans claims that for an incumbent transmission owner, a Commission-approved right of first refusal effectively creates a Federal franchise for transmission development derived from a State franchise for retail electricity. Transmission Agency of Northern California contends that a right of first refusal also may "diminish the incentive for the incumbent utilities to conceive projects in their own service territory." [87]

81. Responding to arguments in favor of a right of first refusal, some commenters argue that concerns about the reliability of a merchant or independent transmission developer's project are unfounded, as the merchant or independent transmission developer will be subject to NERC reliability standards and to the same penalties for noncompliance as an incumbent transmission owner.[88] Pattern Transmission states that a merchant or independent developer has a financial incentive to construct and operate facilities safely and reliably in accordance with all applicable regulatory and industry standards, as its investment is at risk if it does otherwise. With regard to an incumbent transmission owner's obligation to build, some commenters assert that it is not a burden, but rather a privilege, as the incumbent transmission owner is assured the opportunity to recover its costs and earn a return on its investment through the rate base. These commenters argue that a merchant or independent developer would be willing to compete for such an obligation.[89] In response to concerns that a merchant or independent developer would submit an inaccurately low bid to construct a proposed transmission facility, some commenters claim that such a developer is no more likely to do so than an incumbent transmission owner.[90] These same commenters argue that, contrary to what some commenters assert, an incumbent transmission owner will not leave an RTO or ISO if the right of first refusal is eliminated.

82. While some commenters advocate elimination of all rights of first refusal, other commenters support more limited restrictions. For example, Exelon states that "where an independent developer bids on transmission expansion that is justified under existing planning criteria and will be included in rate base, the incumbent transmission owner should be required to match the bid to invoke its right of first refusal." [91] Several commenters argue that a right of first refusal should be allowed for reliability-based projects, but may not be necessary for economic-based or other projects.[92] While AWEA and LS Power both maintain that the right of first refusal should be eliminated, they contend that if the right of first refusal is preserved then those practices should apply only to local reliability projects. Moreover, AWEA asserts that a right of first refusal should be required to be exercised within ninety days. Similarly, ITC Holdings contends that a right of first refusal will continue to impede transmission development if the time for exercising it is allowed to continue indefinitely, and Pacific Gas and Electric argues that any right of first refusal should be exercised in a timely manner. Transmission Access Policy Study Group, however, states that the Commission may need to take other steps in addressing this issue in addition to limiting the time in which a right of first refusal may be exercised. In addition, several commenters contend that placing restrictions on a right of first refusal makes the practice no less discriminatory.[93]

83. EEI argues that while "in general, applicability of a right of first refusal does not create an impediment to transmission planning or development" and that in many cases, "incumbent transmission owners are better situated to build needed transmission within their franchised service territories," if

Southern Companies, WestConnect Planning Parties, and Xcel. However, Old Dominion suggests that the Commission could eliminate the right of first refusal if merchant and independent transmission developers were subject to the same rules and had the same responsibilities as incumbent transmission owners, and could recover their costs through the RTO/ISO tariff.

[85] *E.g.,* Ameren, MidAmerican, and Midwest ISO Transmission Owners.

[86] *E.g.,* American Forest and Paper, AWEA, CAlifornians for Renewable Energy, EPSA, Indicated Partners, Modesto Irrigation District, NationalWind, NextEra, Renewable Energy Systems Americas, Startrans, Starwood, Transmission Access Policy Study Group, Transmission Agency of Northern California, and Transmission Dependent Utility Systems.

[87] Transmission Agency of Northern California at 3.

[88] *E.g.,* Green Energy Express and Pattern Transmission.

[89] *E.g.,* Indicated Partners and Startrans.

[90] *E.g.,* Indicated Partners.

[91] Exelon at 12.

[92] *E.g.,* Allegheny Companies, Dominion, Large Public Power Council, and SPP.

[93] *E.g.,* Indicated Partners.

the Commission finds it necessary to address the exercise of a right of first refusal, it should do so on a case-specific basis.[94] Similarly, the California ISO recommends that the Commission allow the right of first refusal to be addressed through individual RTO and ISO stakeholder processes, rather than adopting generic right of first refusal regulations. Pacific Gas and Electric states that this proceeding should not preempt the California ISO's development of a right of first refusal proposal. In contrast, SPP states that additional clarification and a generally applicable policy regarding the right of first refusal is necessary. The Organization of MISO States argues that, while a right of first refusal may limit competition, any modifications must recognize various State regulatory structures and respect State jurisdiction and statutes. The Alabama PSC argues that the Commission should adopt policies that encourage merchant transmission development only if the State commissions in a region support such policies.

84. In response to the question in the October 2009 Notice regarding barriers to merchant and independent transmission developers' participation in the regional transmission planning process other than a right of first refusal, several commenters state that there are none or that they are unaware of any.[95] However, Pattern Transmission suggests that the uncertainty of recovering the costs associated with participation in the transmission planning process can be a barrier to participation by merchant and independent transmission developers, particularly if the planning process is inefficient and deadlines are not met. Pattern Transmission also asserts that an incumbent transmission owner has an advantage in developing proposals as it has priority access to data. Green Energy Express states that the Commission should ensure "a level playing field with regard to the flow of information, the determination of need, and related interactions between an RTO or ISO or other transmission planning region, incumbent transmission owners and developers, and independent, nonincumbent developers."[96]

85. LS Power states that there are several additional barriers to third party developers' participation in regional transmission planning processes, some of which are unique to certain markets. For example, LS Power states that there are regions in which an independent developer cannot become a transmission owner until it has completed a project and owns the resulting transmission facility. Additionally, LS Power states that it is difficult to develop a project in a region where the load-serving entity is also a transmission owner, as the incumbent utility is often responsible for both generation and transmission planning and resource procurement and may have an incentive to expand its rate base by investing in transmission infrastructure rather than support independent transmission development.

86. Northern Tier Transmission Group suggests that some merchant transmission developers self-impose a barrier to successful participation in the transmission planning process in that they do not submit comparable planning data. As such, Northern Tier Transmission Group is unable to include their projects in its analytical studies.

2. Proposed Reforms Regarding Nonincumbents

87. Based on the comments submitted in response to the October 2009 Notice, there appear to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. Where an incumbent transmission provider has a right of first refusal, a nonincumbent transmission developer risks losing its investment in developing a proposal for submittal to the regional transmission planning process, even if that proposal is selected for inclusion in the regional transmission plan. We are concerned that it may be unduly discriminatory or preferential to deny a nonincumbent transmission developer that sponsors a project that is included in a regional transmission plan the rights of an incumbent transmission provider that are created by a transmission provider's OATT or agreements subject to the Commission jurisdiction.

88. In addition, under these circumstances, nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. If the regional transmission planning process does not consider and evaluate projects proposed by nonincumbents, it cannot meet the principle of being "open." Moreover, such a planning process may not result in a cost-effective solution to regional transmission needs and projects that are included in a transmission plan therefore may be developed at a higher cost than necessary. The result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.

89. To address these issues, we propose a framework that reflects the following reforms, including the elimination from a transmission provider's OATT or agreements subject to the Commission's jurisdiction of provisions that establish a Federal right of first refusal for an incumbent transmission provider with respect to facilities that are included in a regional transmission plan. 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. Further, 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 facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission proposes 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.

90. First, we propose to require that each public utility transmission provider must 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 project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer. These criteria must be included in the public utility transmission provider's OATT and must not be unduly discriminatory or preferential. However, it would not be unduly discriminatory or preferential to have appropriate qualification criteria for all potential transmission owners. Such criteria should be designed to demonstrate that each potential transmission owner has the necessary financial and technical expertise to develop, construct, own, operate, and maintain transmission facilities.[97] Any such criteria must be approved by the Commission. Although we do not

[94] EEI at 9–10.

[95] *E.g.,* Allegheny Companies, CAlifornians for Renewable Energy, Integrys, *et al.,* Maine PUC and Public Advocate, New York PSC, and Xcel.

[96] Green Energy Express at 10.

[97] Nothing would preclude the incumbent transmission owner from agreeing to operate and maintain the facilities. Additionally, nothing in this Proposed Rule is intended to change existing RTO and ISO operational procedures and practices.

propose here to establish a single set of qualification criteria that would apply in all regional transmission planning processes, we seek comment on whether we should do so and if so, what these criteria should be. Instead, we propose that each public utility transmission provider, in cooperation with customers and other stakeholders in its transmission planning region, must participate in a regional transmission planning process that develops qualification criteria that satisfy the requirements of this Proposed Rule.

91. Second, we propose to require that each public utility transmission provider must revise its OATT to 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.[98] In connection with the other aspects of the framework discussed in this section, we also propose to require that all proposals to be considered in a given transmission planning cycle must be submitted by a single, specified date, to minimize the opportunity for other entities to propose slight modifications to already submitted projects.

92. Third, we propose to require that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted to the regional planning process through a transparent and not unduly discriminatory or preferential process. Each public utility transmission provider would be required to describe in its OATT the process used for evaluating whether to include a proposed transmission facility in the regional transmission plan.[99]

93. Fourth, with respect to facilities that are included in a regional transmission plan, we propose to require removal 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.[100] We also propose to require each public utility transmission provider to amend its OATT to describe how the regional transmission planning process in which it participates provides for the sponsor (whether an incumbent transmission provider or a nonincumbent transmission developer) of a facility that is selected through the regional transmission planning process for inclusion in the regional transmission plan to have a right, consistent with State or local laws or regulations, to construct and own that facility.

94. Moreover, because a regional transmission planning process may result in modifications to proposed projects in order to better meet the needs of the region, the public utility transmission provider must ensure that its regional transmission planning process has a mechanism to determine which proposal the modified project is most similar to, with the sponsor of the most similar project having the right, consistent with State or local laws or regulations to construct and own the facilities.

95. Fifth, we propose to require that if a proposed project is not included in a regional transmission plan and if the project's sponsor resubmits that proposed project in a future transmission planning cycle, that sponsor would have the right to develop that project under the foregoing rules even if one or more substantially similar projects are proposed by others in the future transmission planning cycle. The OATT must state that this priority to develop the proposed facility continues for a defined period of time (*e.g.,* for resubmission annually in subsequent transmission planning cycles over a 5-year period).

96. Sixth, we propose to require that, if an incumbent transmission project developer may recover the cost of a transmission facility for a selected project through a regional cost allocation method, a nonincumbent transmission project developer must enjoy that same eligibility. More specifically, each public utility transmission provider must participate in a regional planning process that provides that, when a project proposed by a nonincumbent transmission developer is included in a regional transmission plan, that developer must have an opportunity comparable to that of an incumbent transmission owner to recover the costs associated with developing the project and constructing the transmission facility. Costs associated with a project that is not included in the regional transmission plan, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region's cost allocation process.

97. We emphasize that these proposed reforms would apply only to facilities that are evaluated in a regional transmission planning process and selected for inclusion in a regional transmission plan. We do not propose to modify any existing obligation for an incumbent transmission owner to build unsponsored projects that are identified as necessary in a regional transmission plan.[101] In addition, where an incumbent transmission owner has the right to build, own, and recover costs for upgrades to its own existing transmission facilities (*e.g.,* tower change out and reconductoring), such right would not be affected by the reforms proposed here.

98. We also emphasize that these proposed reforms would affect only a right of first refusal established in a transmission provider's OATT or agreements subject to the Commission's jurisdiction. This Proposed Rule does not address, propose to change, or seek to preempt any State or local laws or regulations.

99. Finally, we do not propose here to require a transmission developer that does not seek to use the regional cost allocation process to participate in the regional transmission planning process, as some commenters recommend. For example, because a merchant transmission developer assumes all financial risk for developing its project and constructing the proposed 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 project or securing eligibility to use a regional cost allocation method. A

[98] The information about its proposed project that a sponsor provides also should include, as relevant, engineering studies, cost analyses, and any other detailed reports completed by the project sponsor as needed to facilitate evaluation of the project in the regional transmission planning process.

[99] The description would need to provide sufficient detail so that an entity that proposed a project could determine why the project was included or not included in the regional transmission plan. In addition to addressing concerns about undue discrimination or preference, the description would facilitate understanding of the relative weight placed on various benefits associated with competing proposals (*e.g.,* one proposal might address only a reliability-driven transmission need, while another proposal might also provide greater benefits in terms of congestion relief or advancement of public policy requirement established by State or Federal laws or regulations that a transmission planning region has identified).

[100] If a Commission-approved tariff or agreement contains a reference to a right provided under state or local laws or regulations, such a provision would not be subject to this requirement.

[101] For example, in some RTO and ISO regions, transmission owners have obligations to build certain transmission facilities identified by the RTO or ISO. As new transmission owners, including nonincumbent transmission owners, join the RTO or ISO, they will incur the obligations accompanying that status in the RTO or ISO's tariff and other governing documents. We note that provisions imposing such obligations may need to be modified to reflect how they will apply to nonincumbent transmission project developers. We also note that before turning to a transmission owner with such an obligation, the RTO or ISO could conduct a competitive bidding process to assign construction rights for an unsponsored project in its regional transmission plan.

developer that does not seek to use the regional cost allocation process nevertheless would be required to comply with all reliability requirements applicable to facilities in the transmission planning region in which its project would be located. In addition, such a developer is not prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.

100. As discussed above, in response to the October 2009 Notice, many commenters link the right of first refusal for an incumbent utility to its obligation to construct new facilities if called upon to do so. While the Commission acknowledges these comments, we preliminarily find that these two practices are not, and should not be, linked within regional transmission planning processes. That is, while a public utility transmission owner may have accepted an obligation to build in relation to its membership in an RTO or ISO, this obligation is not directly dependent on that transmission provider having a corresponding right of first refusal with regard to a proposal to construct and own a new transmission facility located in that region. What is important from the Commission's perspective is that the documents approved by the Commission must not be unduly discriminatory. The Commission preliminarily finds that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission approved OATT or agreement, receive different treatment in the transmission planning and selection process, and both should share similar benefits and obligations commensurate with that participation.

101. We seek comment on how the reforms proposed in this section of the Proposed Rule would affect the rights, obligations, and responsibilities of incumbent and nonincumbent transmission providers. In particular, we seek comment on the relationship or lack of relationship between a right of first refusal and an obligation to build. We also seek comment on whether it would be appropriate to retain a Federal right of first refusal in an OATT or other documents subject to the Commission's jurisdiction. If not, why not? If so, would it be appropriate to retain an obligation to build for an incumbent transmission provider while removing a Federal right of first refusal for that incumbent?

D. Interregional Coordination

1. The Need for Interregional Planning Reforms

102. As discussed above, the transmission planning principles established in Order Nos. 890 and 890–A establish a framework for transmission planning at the local and regional levels. In Order No. 890–A, the Commission emphasized that effective regional planning should include coordination among regions. Further, the Commission stated that regions and subregions should coordinate as necessary to share data, information and assumptions to maintain reliability and allow customers to consider the resource options that span the regions.[102] In several of the Order No. 890 compliance orders, the Commission requested more detailed information regarding compliance with this aspect of the regional participation principle.[103]

103. Within that 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 plans for upgrades 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.[104] Additionally, some neighboring transmission providers have undertaken joint transmission planning pursuant to bilateral agreements.[105] However, as observed in the October 2009 Notice, there are few processes in place to analyze whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans.[106]

104. The October 2009 Notice 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 October 2009 Notice also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.[107]

105. In response to the October 2009 Notice, some commenters state that the need for supplemental interregional transmission planning processes cannot be evaluated until stakeholders gain more experience with the regional transmission planning processes conducted pursuant to Order No. 890, and thus oppose Commission action on this issue at this time.[108] Other commenters state that the lack of interregional planning is a considerable problem and that transmission planning could be enhanced by increasing the amount of coordination that occurs between neighboring transmission planning regions.[109]

106. More specifically, several commenters advocate expansion of interregional transmission planning, but disagree as to the extent to which interregional coordination should be institutionalized. Proposals range from requiring regional transmission planning entities to comply with Order No. 890 transmission planning principles,[110] to requiring greater coordination among existing transmission planning regions,[111] to expanding the authorities of regional transmission planning entities.[112] Some

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

[103] *See, e.g., Southern Co. Servs., Inc.;* 124 FERC ¶ 61,265, at P 70 (2008); *United States Department of Energy—Bonneville Power Administration,* 124 FERC ¶ 61,054, at P 65 (2008); *Southwest Power Pool, Inc.,* 124 FERC ¶ 61,028, at P 49 (2008).

[104] Such analysis is consistent with one aspect of the Regional Participation transmission planning principle that the Commission established in Order No. 890. On that issue, the Commission stated: "[I]n addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each transmission provider will be required to coordinate with interconnected systems to: (1) Share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data, and (2) identify system enhancements that could relieve congestion of integrate new resources * * *" Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

[105] *See, e.g.,* Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (Midwest Independent Transmission System Operator, Inc., Second Revised Rate Schedule FERC No. 5; PJM Interconnection, L.L.C. Second Revised Rate Schedule FERC No. 38).

[106] October 2009 Notice at 2.

[107] *Id.* at 3.

[108] *E.g.,* American Transmission, Consolidated Edison, et al., Dominion, Eastern Interconnection Planning Collaborative Analysis Team, Imperial Irrigation District, New York ISO, Public Power Council, South Carolina Electric & Gas, and Southern Companies.

[109] *E.g.,* Duke, Exelon, NextEra, Ohio Commission, Old Dominion, Organization of MISO States, PSEG Companies, Transmission Access Policy Study Group, and Transmission Dependent Utility Systems.

[110] *E.g.,* Old Dominion.

[111] *E.g.,* AWEA, Pioneer Transmission, PSEG Companies, Public Interest Organizations & Renewable Energy Groups, Transmission Access Policy Study Group, and Transmission Dependent Utility Systems.

[112] Regional transmission planning entities would be empowered "to make specific project recommendations at the end of the planning process and to enter binding, near-juridical findings of fact and conclusions related to the need and economic benefits of specific projects or solutions." San Diego Gas & Electric at 6.

commenters suggest that the Commission should require interregional transmission planning or develop *pro forma* seams agreements that describe the requirements for coordinating transmission planning with a neighboring transmission planning region.[113]

107. San Diego Gas & Electric, for example, states that, in the West, transmission planning is a hodgepodge of balkanized processes resulting in a flood of proposed interstate transmission facilities but with virtually no consideration given to which of the proposed facilities would be most effective in meeting the needs of the broadest set of constituents. San Diego Gas & Electric also states that little serious consideration is given to how various project proposals could be modified, combined, or eliminated so as to make the best possible use of available transmission corridors, minimize adverse environmental impacts, and enhance overarching system efficiencies.[114]

108. Pioneer Transmission states that it has a unique perspective on interregional transmission planning issues, as it spent the last year and a half working with the Midwest ISO and PJM in an effort to develop extra high voltage transmission facilities that will be located in both the Midwest ISO and PJM footprints. Pioneer Transmission states that although the Midwest ISO and PJM have undertaken various studies and have worked cooperatively with Pioneer Transmission, they have been hampered in their efforts to assess the Pioneer project for inclusion in their transmission plans because neither RTO has in place formal procedures for evaluating interregional projects.[115]

109. The Ohio Commission states in its comments that "[j]ust as the development of RTOs and ISOs was encouraged to better coordinate individual transmission owners' and operators' plans, the development of inter-regional planning committees to review and coordinate individual and RTO and ISO plans should be encouraged." [116] The California ISO states that it would be easier to analyze and justify transmission facilities that would be located in more than one region if the underlying data were consistent in all of the areas that are part of evaluating the transmission project in question.[117] Similarly, Public Interest Organizations & Renewable Energy Groups state that the Commission should require coordinated transmission infrastructure plan development by regional or interregional transmission planning authorities informed by interconnection-wide assessments and broad stakeholder input.

110. The October 2009 Notice also recognized that proposals to implement interconnectionwide transmission planning were being developed in response to the above-noted funding opportunities that DOE offered under the American Recovery and Reinvestment Act of 2009. The October 2009 Notice observed that it was not clear whether those activities would result in a regular process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing transmission planning processes conducted in accordance with Order No. 890.[118]

111. In response to the October 2009 Notice, some commenters state that interconnectionwide transmission planning undertaken pursuant to the ARRA should be given a chance to mature before the Commission takes additional action with respect to transmission planning.[119] Other commenters emphasize that funding under the ARRA is an important one-time opportunity, but should not be viewed as a prerequisite for initiating or expanding upon other transmission planning efforts.[120] For example, Exelon states that the ARRA-funded transmission planning for the Eastern Interconnection is a positive effort, but is aimed at evaluating what would happen under various scenarios rather than at evaluating solutions and identifying the best solution for any given transmission planning problem. AWEA states that the Commission should not rely on interconnectionwide transmission planning undertaken pursuant to the ARRA as the sole means for reforming the transmission planning process because the ARRA-funded efforts cannot be expected to lead to the near-term changes that need to be implemented in order to support development of renewable energy resources.

112. The Commission supports and encourages the interconnectionwide transmission planning efforts being undertaken pursuant to the ARRA. As noted above, broad participation in sessions to date related to these efforts suggests that that the availability of Federal funds to pursue interconnectionwide transmission planning has increased awareness of the potential for greater coordination among regions in transmission planning. The Commission anticipates that the ARRA-funded efforts will enhance transmission planning by, among other actions, building upon local and regional transmission planning processes and improving capabilities to model the development of transmission enhancements for the various scenarios of interest to State and Federal policy makers and other stakeholders, as well as Canadian provincial policy makers in the Western Interconnection. We emphasize that this Proposed Rule, which does not require interconnectionwide planning or cost allocation, is not intended to interfere with the efforts already underway in ARRA-funded transmission planning initiatives.

113. However, even with these important steps toward interconnection-wide scenario analysis, the Commission remains concerned 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. These circumstances may result in transmission rates that are unjust and unreasonable. Therefore, the Commission proposes reforms that are intended to improve coordination between neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities.

2. Proposed Interregional Planning Reforms

114. We propose 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, as discussed below.[121] This coordination between transmission planning regions must be reflected in an

[113] *E.g.,* AEP, Energy Future Coalition, Old Dominion, Pioneer Transmission, Public Interest Organizations & Renewable Energy Groups, SPP, Transmission Access Policy Study Group, and Transmission Dependent Utility Systems.

[114] San Diego Gas & Electric at 5.

[115] Pioneer Transmission at 1–2.

[116] Ohio Commission Comments at 6.

[117] California ISO at 8.

[118] October 2009 Notice at 2–3.

[119] *E.g.,* ColumbiaGrid, NARUC, New England States' Committee on Electricity, and Organization of MISO States.

[120] *E.g.,* Eastern Interconnection Planning Collaborative Analysis Team, Entergy, and Progress Energy.

[121] This proposal does not require a public utility transmission provider to enter into an interregional transmission planning agreement with a neighboring transmission planning region in another interconnection.

interregional transmission planning agreement to be filed with the Commission.

115. The interregional transmission planning agreement may be developed on behalf of the public utility transmission providers within multiple transmission planning regions. For example, two RTOs may set forth the requirements of their interregional transmission planning coordination as part of an overall joint operating agreement between them. A public utility transmission provider that is not in an RTO or ISO may, for example, work with other transmission providers that participate in its regional transmission planning process to create and enter into a multilateral interregional transmission planning agreement with transmission providers in a neighboring transmission planning region. Although not required under this proposal, we encourage public utility transmission providers to explore possible multilateral interregional transmission planning agreements among several, or even all, regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives. We note that multilateral interregional transmission planning agreements may minimize the growing number of planning meetings that some stakeholders suggest pose barriers to their meaningful participation in the planning processes, given their limited resources.

116. The interregional transmission planning agreement must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that are not proposed but that could address transmission needs more efficiently than separate intraregional facilities.

117. While the Commission encourages every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement, there are certain elements that we propose each public utility transmission provider must ensure are included in any interregional transmission planning agreement in which it participates. Including these elements will help to ensure a proactive, comprehensive process. Specifically, we propose that an interregional transmission planning agreement must include: (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; (2) an agreement to exchange at least annually planning data and information; (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions; and (4) a commitment to maintain a Web site or e-mail list for the communication of information related to the coordinated planning process.

118. With respect to the third proposed requirement for an interregional transmission planning agreement, the Commission proposes that the sponsor of a project that would be located in both transmission planning regions to which that agreement applies must first propose its project in the transmission planning process of each of those transmission planning regions. The Commission further proposes 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 project. The Commission proposes 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 project. Finally, the Commission proposes 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 proposed below in this NOPR.

119. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule, including the proposed required elements of an interregional transmission planning agreement and any other elements that should be part of an interregional transmission planning agreement. In particular, we seek comment on how such an agreement would be implemented in non-RTO or ISO regions and on the impact that an interregional transmission planning agreement would likely have on the development of interregional transmission facilities.

120. We recognize that development of interregional transmission planning agreements would take time and would necessarily depend on progress at the regional level. Accordingly, the Commission proposes to require the interregional transmission planning agreements to be submitted to the Commission no later than one year after the effective date of the final rule issued in this proceeding.

V. Proposed Reforms: Cost Allocation

A. Introduction

1. Order No. 890's Transmission Planning Principle on Cost Allocation for New Transmission Facilities

121. 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. The Commission stated that knowing how the costs of new 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.[122]

122. In light of this close relationship, the Commission included a principle entitled "Cost Allocation for New Projects" among the Order No. 890 transmission planning principles. The Commission stated that the Order No. 890 Cost Allocation principle was intended to apply to projects that did not fit under existing cost allocation methods. As examples of such projects, the Commission cited regional projects involving several transmission owners and economic projects that are identified pursuant to the Order No. 890 economic planning studies principle for transmission planning, rather than through individual requests for transmission service.[123]

123. The Commission did not impose a particular cost allocation method in Order No. 890, but instead permitted public utility transmission providers, customers, and other stakeholders to determine a method that would be appropriate given the needs of the region. While allowing this flexibility among regions, the Commission also stated that providing some overall guidance on the issue was appropriate. The Commission stated that when considering a dispute over cost allocation, it would exercise its judgment by weighing several factors. First, the Commission stated that it would consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and

[122] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

[123] *Id.* P 558.

those that otherwise benefit from them. Second, the Commission stated that it would consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, the Commission stated that it would consider whether the proposal is generally supported by State authorities and participants across the region.[124]

124. The Commission also stated that these factors are particularly important as applied to economic projects that are identified pursuant to the Order No. 890 economic planning studies principle for transmission planning, such as upgrades to reduce congestion or enable groups of customers to access new generation. The Commission stated that, as a general matter, the beneficiaries of any such project should agree to support its costs. The Commission recognized, however, 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 benefit from it. The Commission also stated that a range of solutions to free rider problems is available, noting that different regions have attempted to address those problems in a variety of ways.[125]

125. To comply with the cost allocation principle, the Commission directed each public utility transmission provider to clearly define the details of its cost allocation method as part of a new attachment to its OATT. The Commission stated that each proposal should identify the types of new projects that are not covered under previously existing cost allocation methods and, therefore, would be affected by the Order No. 890 cost allocation principle.[126] The Commission also stated that it is important that each region address these cost allocation issues up front, at least in principle, rather than having them relitigated each time a project is proposed.[127] The Commission explained that up-front identification of how the cost of a facility will be allocated will allow transmission providers, customers, and potential investors to make the decision whether or not to build that facility on an informed basis.[128]

126. After several rounds of compliance filings, the Commission approved various public utility transmission providers' proposals pursuant to the cost allocation principle. The Commission found that the proposals adequately identified both the types of new projects that were not covered under previously existing cost allocation methods and new methods for allocating the cost of those projects.

127. Particularly 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. Under a participant funding approach to cost allocation, the costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.

128. For example, El Paso Electric proposed in its Order No. 890 compliance filing to use a cost allocation method in which such entities would share the costs proportionally based on each participant's desired use of the facility to be constructed.[129] Other members of WestConnect, such as Public Service Company of Colorado, filed and now use similar participant funding cost allocation methods.[130] South Carolina Electric & Gas included in its Order No. 890 compliance filing the Southeast Inter-Regional Participation Process (SIRPP) provisions stating that costs for economics-driven upgrades will be born entirely by the transmission owner that builds the facilities.[131] Similarly, Entergy filed and had approved a method where the costs for projects developed under its Regional Planning Process and its interregional transmission planning process would be born by the party that constructs the facilities.[132] ColumbiaGrid and the Northern Tier Transmission Group both utilize a study committee process whereby alternative cost allocation methods can be proposed for projects within their respective regions.[133] However, both ColumbiaGrid and Northern Tier Transmission Group use a process where, if no agreement on cost allocation among the study team participants or the project proponents is obtained, the entities requesting the project will bear the costs.

2. October 2009 Notice and Subsequent Comments

129. As discussed above, in the October 2009 Notice, the Commission posed a number of questions with respect to allocating the cost of transmission facilities. Those questions drew wide-ranging responses as to whether further Commission action on cost allocation is needed at this time and, if so, what that action should be.

130. Among the commenters, there is general agreement that the Commission should not supersede existing, ongoing processes in various parts of the country that are attempting to address regional and interregional cost allocation issues.

131. Nonetheless, commenters supporting further Commission action on cost allocation at this time generally assert that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.[134] Many commenters argue that a clear path to cost recovery is necessary for a new transmission project to move beyond the evaluation stage and to be included in any regional transmission planning process and ultimately to proceed to construction.[135] Such commenters indicate that risks associated with cost recovery—together with the risks associated with permitting and siting—are among the most significant obstacles to the construction of a new transmission facility, especially if customers that are allocated costs do not perceive that they will benefit from the proposed facility.[136] Old Dominion emphasizes that many of the obstacles inhibiting transmission development are interrelated, but that greater certainty on cost allocation would likely ease access to capital for proposed facilities.[137]

132. Several commenters specifically address cost allocation as an impediment to the development of generation to satisfy renewable portfolio

[124] *Id.* P 559.

[125] *Id.* P 561 ("[D]ifferent regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project.").

[126] *Id.* P 558.

[127] *Id.* P 561.

[128] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 251. The Commission also stated that neither adoption of a cost allocation method nor identification of an upgrade (whether driven by reliability or economics) in a transmission plan triggers an obligation to build. *Id.*

[129] *El Paso Electric Company,* 124 FERC ¶ 61,051, at P 44 (2008).

[130] *Xcel Energy Services, Inc.—Public Service Company of Colorado,* 124 FERC ¶ 61,052 (2008).

[131] *South Carolina Electric & Gas Company,* 127 FERC ¶ 61,275, at P 50 (2009).

[132] *Entergy Services, Inc.,* 127 FERC ¶ 61,272 (2009).

[133] *See Avista Corporation,* 128 FERC ¶ 61,065 (2009) and *Idaho Power Company,* 128 FERC ¶ 61,064 (2009).

[134] *E.g.,* APPA, National Rural Electric Coops, Transmission Access Policy Study Group, Transmission Dependent Utility Systems, and California ISO.

[135] *E.g.,* American Transmission, AWEA, E.ON Climate & Renewables North America, Energy Future Coalition, and NextEra.

[136] *E.g.,* AWEA, Transmission Dependent Utility Systems, Xcel, Transmission Access Policy Study Group, and National Rural Electric Coops.

[137] Old Dominion at 26.

standards implemented by the states.[138] AWEA, for example, states that cost allocation policies are the biggest impediment to construction of new transmission facilities, regardless of location, and that costs should be assigned to all entities that benefit from a new facility. AWEA further comments that a participant funding cost allocation method does not achieve that goal.[139] These commenters also state that uncertainty over cost allocation imposes significant costs on customers attempting to export energy from renewable resources and inhibit planning for the integration of the most economic generation resources into the transmission grid. Maine PUC and Public Advocate state that the existing ISO–NE cost allocation methods are not optimal when considering large amounts of wind integration.[140]

133. Similarly, the majority of commenters that address cost allocation for large, interregional transmission facilities agree that the Commission should provide more guidance on cost allocation.[141] Some commenters complain that as a general matter, the Commission has addressed cost allocation methods only for facilities within the footprint of a single transmission provider or a single RTO or ISO, and not for interregional projects. For example, AEP states that it has experienced delays in developing transmission facilities that cross RTO boundaries as a result of uncertainty over cost allocation, as well as difficulties with how the facilities are to be planned.

134. Some of these commenters assert that the expansion of regional power markets and the increasing adoption by State governments of renewable energy requirements have led to a growing need for new transmission facilities that cross several utility and/or RTO or ISO regions. These commenters generally support, or state that they do not oppose, the Commission establishing a process to help stakeholders address cost allocation matters over larger geographic areas. For example, California ISO and the California Commission comment that, although cost allocation within the California ISO works well, they support the Commission creating a process to consider cost allocation over a larger region in the West.

135. In addition, the comments in response to the October 2009 Notice reflect a general consensus that those who share in the benefits of transmission projects should also share in their costs. However, there is no consensus on what types of benefits should be considered or how such benefits should be calculated. Certain commenters, for example, support recognition of a broad spectrum of benefits that may stem from transmission development, such as environmental impacts, land conservation and energy security.[142] Other commenters urge the Commission to avoid a uniform approach to determining the benefits of transmission projects.[143]

136. Several commenters suggest that if the Commission decides to establish a default cost allocation method for new transmission facilities, such a method should be employed and enforced only when stakeholders are unable to agree upon their own regional cost allocation method or methods.[144] For example, American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants state that the Commission could create a generic cost allocation method as a backstop, which would apply when parties or regions could not come to their own agreement. Other commenters express the view that the Commission should create one or more rebuttable presumptions about who benefits from various types of facilities in order to make cost allocation easier.[145]

137. Finally, many commenters state that no further generic Commission action on cost allocation is needed at this time because the processes in their own regions already address, or are now working to address, cost allocation. For example, in the Southeast, some commenters state that their processes for cost allocation are working well and argue that the Commission should continue to allow regional flexibility on cost allocation processes.[146] Similarly, in the West, some commenters state that cost allocation in their region is not a problem.[147]

B. Legal Authority and Need for Reform

138. Based on the comments received in response to the October 2009 Notice, the Commission believes that further reform with respect to transmission cost allocation methods may be necessary in order to ensure that the rates, terms and conditions of transmission service in interstate commerce are just and reasonable and not unduly discriminatory or preferential.

1. The Cost Causation Principle

139. Under sections 205 and 206 of the FPA, the Commission is responsible for ensuring that the rates, terms, and conditions for transmission of electricity in interstate commerce are just, reasonable, and not unduly discriminatory or preferential.[148] With respect to this responsibility, the Commission and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the "cost causation" principle.

140. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has defined the cost causation principle as follows: "[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them." [149] The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on that definition, stating, "All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." [150] The Commission has

[138] *E.g.,* AWEA at 9–10, American Transmission and Exelon.

[139] AWEA at 4. *See also* Transmission Access Policy Study Group at 25–27.

[140] Maine PUC and Public Advocate at 7–8.

[141] *E.g.,* AEP, ITC Holdings, and Exelon.

[142] *E.g.,* AEP, AWEA, Baltimore Gas and Electric, Energy Future Coalition, Green Energy Express, ITC Holdings, MidAmerican, National Audubon Society, NextEra, and Public Interest Organizations & Renewable Energy Groups.

[143] *E.g.,* ColumbiaGrid, ConEd, Delaware Municipal and Southwestern Electric, and Northeast Utilities.

[144] *E.g.,* American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants.

[145] *E.g.,* ITC Holdings, MidAmerican, PJM, Solar Energy Industries, and WIRES.

[146] *E.g.,* Entergy, Southern Companies, and Florida Transmission Providers.

[147] *E.g.,* ColumbiaGrid, Northern Tier Transmission Group, Transmission Agency of Northern California, Salt River Project and WestConnect Planning Parties.

[148] 16 U.S.C. 824d, 824e.

[149] *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) (*K N Energy*).

[150] *Illinois Commerce Comm'n* v. *FERC,* 576 F.3d 470, 476 (7th Cir. 2009) (*Illinois Commerce Commission*) (citing *K N Energy,* 968 F.2d at 1300; *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 708 (D.C. Cir. 2000); *Pacific Gas & Elec. Co.* v. *FERC,* 373 F.3d 1315, 1320–21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*Midwest ISO*

frequently made similar statements with respect to the cost causation principle. For example, as noted above, the Commission stated in Order No. 890 that one factor it weighs when considering a dispute over cost allocation is whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them.[151]

141. In applying the cost causation principle, the Commission has generally allocated costs to beneficiaries that have entered a voluntary arrangement with the public utility that is seeking to recover those costs. One example of a voluntary cost recovery arrangement with a public utility is voluntary membership in an RTO or ISO that makes an entity subject to the cost allocation provisions of the RTO's or ISO's tariff.[152] The Commission also has permitted joint-ownership agreements where the owners share the costs of the new transmission facilities.

142. The cost causation principle, however, is not limited to voluntary arrangements. Indeed, if the Commission were limited to allocating costs only to beneficiaries that voluntarily accept those costs, then the Commission could not fulfill its responsibilities under the FPA. If the Commission could not address free rider problems associated with new transmission investment, then it could not ensure that transmission rates are just and reasonable and not unduly discriminatory. 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, as the Commission also recognized in Order No. 890. In other words, the Commission may determine that an entity's status as a beneficiary of a transmission facility identified through an appropriate process is relevant for purposes of applying the cost causation principle, even if that beneficiary has not entered a voluntary arrangement with (*e.g.,* as a customer of) the public utility that is seeking to recover the costs of that facility.

143. The Commission has expressed a willingness to make such a determination. For example, when presented with concerns about parallel path flow,[153] the Commission has offered repeatedly that if a public utility can demonstrate that a transaction is a burden on its system, then that utility can propose a transmission service rate for Commission consideration that would account for the unauthorized use of its system.[154] The Commission has cautioned against the hasty submittal of such unilateral filings, describing its general policy as expecting owners and controllers of transmission facilities to attempt to resolve parallel path flow issues on a consensual, regional basis.[155] Nonetheless, if approved by the Commission, such a proposal to address parallel path flow would allow a public utility to recover costs from a beneficiary of its system in the absence of a voluntary arrangement between the utility and that beneficiary.

144. The Commission also affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM). Specifically, the Commission directed Midwest ISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other's footprint.[156] Echoing precedent applying the cost causation principle, the Commission later conditionally accepted a proposal that Midwest ISO and PJM submitted in compliance with that directive on the grounds that it "more accurately identifies the beneficiaries and allocates the associated costs" than did the cost allocation methods that were previously in place.[157]

145. These examples show that the Commission has asserted its authority to allocate the costs of jurisdictional facilities to beneficiaries whether or not those beneficiaries have entered into a voluntary agreement with the public utility that is seeking to recover those costs.

146. In addition, courts have affirmed that the cost causation principle allows the Commission to allocate at least some types of costs to beneficiaries that are not customers of the public utility that is seeking to recover the costs in question. For example, the D.C. Circuit addressed this issue in a case that involved a proposal for Midwest ISO to recover administrative costs through a charge that would apply to transmission loads subject to the Midwest ISO's tariff rates: *i.e.,* new wholesale loads and unbundled retail loads, but not bundled retail loads and loads served pursuant to grandfathered contracts.[158] Describing the core issue as whether the Commission's orders comported with the cost causation principle, the D.C. Circuit found that the Commission reasonably allocated the administrative costs more broadly than Midwest ISO proposed.[159] After stating that the subject costs were the administrative costs of having an ISO, the D.C. Circuit found that the Commission correctly determined that bundled and grandfathered loads should share the cost of having an ISO because they drew benefits from Midwest ISO.[160]

147. Thus, in 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 a voluntary arrangement with the public utility that

Transmission Owners); *Alcoa Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P.* v. *FERC,* 285 F.3d 1, 4–5 (D.C. Cir. 2002) (*Sithe*); 16 U.S.C. 824d).

[151] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

[152] The Commission notes that RTO or ISO membership does not eliminate the need to satisfy the other aspects of the cost causation principle that are discussed above.

[153] 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).

[154] *See, e.g., Amer. Elec. Power Svc. Corp.,* 49 FERC ¶ 61,377, at 62,381 (1989).

[155] *Id. See also Southern California Edison Co.,* 70 FERC ¶ 61,087, at 61,241–42 (1995).

[156] *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 Midwest ISO 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 Midwest ISO and PJM developed in order to comply with a previous Commission directive. *See Alliance Cos.,* 100 FERC ¶ 61,137, at P 48, 53 (2002).

[157] *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).

[158] *Midwest ISO Transmission Owners,* 373 F.3d 1361. The D.C. 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.

[159] *Id.* at 1370.

[160] *Id.* at 1370–71.

is seeking to recover the costs of that facility. After satisfying this standard with respect to beneficiary identification, the cost causation principle also requires the Commission to ensure that the costs allocated to a beneficiary under a cost allocation method are at least roughly commensurate with the benefits that are expected to accrue to that entity.[161] On this point, the D.C. Circuit has explained that "the cost causation principle does not require exacting precision in a ratemaking agency's allocation decisions." [162]

2. Need for Reform

148. The Commission's responsibility under FPA sections 205 and 206 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 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.

149. The Commission has previously recognized changes in circumstances that warranted changes in the manner by which public utilities recover transmission costs. In the early 1990s, the Commission identified "dramatic changes which the electric industry has faced, and will face in the near term," such as "increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems," as well as the initial filing of open access transmission tariffs.[163] To account for those developments and the industry's changing needs, the Commission issued a policy statement that increased flexibility with respect to transmission pricing.[164]

150. Many of those changes have not only continued but also accelerated in recent years. For example, as commenters stated in response to the October 2009 Notice, the 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. The industry's continuing transition from relatively localized trading to larger regional power markets also results, among other effects, in broader diffusion of the benefits associated with transmission upgrades and new transmission facilities.

151. Similarly, 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 that cross several utility and/or RTO or ISO regions. Transmission facilities that are needed to comply with State renewable portfolio standard measures illustrate the increasing potential for benefits associated with meeting public policy-driven transmission needs.

152. More generally, as stated above, challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. As noted above, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, 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 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. In addition, cost allocation within RTO or ISO regions, particularly those that encompass several states, is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair. Some comments filed in response to the October 2009 Notice present these types of concerns and state the resultant uncertainty regarding cost allocation remains an impediment to development of needed transmission facilities.

153. The risk of the free rider problems associated with new transmission investment that the Commission described in Order No. 890 is also 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. On one hand, a cost allocation method that relies exclusively on a participant funding approach, 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 are allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose inclusion of the facility in a regional transmission plan or to otherwise impose obstacles that delay or prevent the facility's construction.

154. In light of these challenges and recent developments affecting the industry, the Commission is concerned 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.

C. Proposed Reforms

155. The Commission proposes to amend its regulations to address the concerns discussed above.

156. First, we propose to more closely align transmission planning and cost allocation processes. A transmission planning process includes a facility in a transmission plan in order to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, reduce congestion and thereby increase access to lower-cost resources, or enable compliance with public policy requirements established by State or Federal laws or regulations. Because such purposes involve the identification of expected beneficiaries—either explicitly or implicitly—establishing a closer link between transmission planning and cost

[161] *Illinois Commerce Commission,* 576 F.3d 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 Midwest ISO 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.

[162] *Midwest ISO Transmission Owners,* 373 F.3d 1361 at 1371 (citing *Sithe,* 285 F.3d 1 at 5).

[163] *See Notice of Technical Conference and Request for Comments in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act,* 58 FR 36400, at 36401 (1993).

[164] *Policy Statement in Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act,* FERC Stats. & Regs., Regulations Preambles January 1991–June 1996 ¶ 31,005 (1994).

allocation will address in part the Commission's concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities.

157. The Commission has previously suggested that transmission planning at least on a regional basis is closely related to cost allocation. As noted above, this premise underlies the Commission's establishment in Order No. 890 of a transmission planning principle on cost allocation for new transmission facilities. In addition, the Commission has explained that it may be appropriate to have different cost allocation methods for facilities that are planned for different purposes or pursuant to different transmission planning processes. For example, the Commission distinguished between existing facilities in Midwest ISO and PJM for which it found that license plate rates are appropriate, and new facilities in those regions for which it approved broader cost allocation methods.[165] The Commission found it significant that Midwest ISO and PJM plan the construction of new facilities based on each RTO's independent transmission planning process, which helps to ensure that new projects are necessary to meet the reliability and economic needs of each RTO's system as a whole. The Commission also noted that Midwest ISO and PJM plan certain new facilities pursuant to a joint RTO planning process under a Joint Operating Agreement. By contrast, the Commission stated that decisions to build existing facilities within Midwest ISO and PJM were not made as part of any regional planning process.[166]

158. The Commission recognizes that identifying which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. The Commission believes that a transparent transmission planning process is the appropriate forum to address these issues. In addition, addressing these issues through the transmission planning process would increase the likelihood that facilities included in transmission plans are actually constructed, rather than being included in a transmission plan only to later encounter cost allocation disputes that prevent their construction.

159. Accordingly, the Commission proposes to require that every public utility transmission provider have in place 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 located within the region would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region.

160. An RTO or ISO or the public utility transmission providers in a transmission planning region may have a single cost allocation method for all new transmission facilities or different methods for different types of facilities. For example, cost allocation methods may distinguish among facilities that are driven by needs associated with maintaining reliability, relieving congestion, and achieving public policy requirements established by State or Federal laws or regulations, all of which would be required to be considered in the regional transmission planning process as explained elsewhere in this Proposed Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of project currently have transmission planning procedures and cost allocation methods that refer only to the first two categories of transmission projects. The Proposed Rule would permit a public utility transmission provider or transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three is considered in the transmission planning process and there is a means for allocating the costs of each type of facility to beneficiaries.

161. Second, we propose to 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.

162. Third, to ensure that the cost allocation method or methods are just and reasonable and not unduly discriminatory or preferential, we propose to assess each cost allocation method based upon the cost allocation principles set out in the following sections, one set of principles for intraregional facilities and another for interregional facilities. To reiterate, we propose that the cost allocation method or methods be applied to new transmission facilities included in the transmission plan produced by the transmission planning process in which the public utility transmission provider participates.

163. Finally, we note that under our proposals, public utility transmission providers will have the first opportunity to develop cost allocation methods for intraregional and interregional transmission facilities in consultation with customers and other 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 the Commission's proposed requirements.

1. Intraregional Cost Allocation

164. An intraregional transmission facility is defined as a transmission facility located entirely within the geographic boundaries of one transmission planning region. As proposed here, each RTO or ISO on behalf of its transmission owning members, or the individual public utility transmission providers in a non-RTO or ISO transmission planning region, would be required to demonstrate through a compliance filing that it has a cost allocation method or methods that address cost recovery for each new transmission facility included in its regional transmission plan and that satisfy the following 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.[167] 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

[165] *Amer. Elec. Power Serv. Corp.* v. *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,083, at P 13–24 (2008).

[166] *Id.* P 96.

[167] *Illinois Commerce Commission,* 576 F.3d 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 Midwest ISO 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.

requirements established by State or Federal laws or regulations that may drive transmission needs.[168]

(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 an intraregional 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.[169] 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 rule.

165. In proposing these principles, the Commission does not intend to prescribe a uniform approach to cost allocation for new intraregional transmission facilities. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, this Proposed Rule would allow the public utility transmission providers in each transmission planning region to develop a transmission cost allocation method that best suits the needs of that transmission planning region.

166. However, the Commission proposes that, if the public utility transmission providers in a transmission planning region, in consultation with customers and other stakeholders, cannot agree on a cost allocation method for new intraregional transmission facilities that satisfies these principles, the Commission would use the record in the relevant compliance filing proceeding as a basis for applying these principles to develop a cost allocation method that meets the Commission's requirements. Consistent with the Commission's intention not to prescribe a uniform approach, this cost allocation method would not necessarily be the same for every transmission planning region where the public utility transmission providers are unable to agree on a cost allocation method that satisfies the principles.

167. The Commission recognizes that several approaches to cost allocation may satisfy the proposed 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 facility or class or group of facilities (*e.g.,* all transmission facilities at 345 kV or higher), especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments. Similarly, other methods that propose cost allocation to a narrower class of beneficiaries may be appropriate, provided that the method reflects an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region.

168. In addition, the principles proposed in this rulemaking do not foreclose the opportunity for a transmission developer or individual customer to voluntarily assume the costs of a new transmission facility. In other words, the proposed principles would not prohibit voluntary participant funding. However, if a transmission developer believes that others in the transmission planning region may benefit from a new transmission facility and want to seek broader cost allocation, then that developer must be permitted to propose its project in the regional transmission planning process that will evaluate the project's beneficiaries. If the facility is included in the regional transmission plan, the costs of that facility must be eligible for allocation pursuant to the Commission-approved method for allocating the cost of a new transmission facility in that plan.[170] As stated above, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission described in Order No. 890. Such a cost allocation method would not satisfy the proposed principles.

169. 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 intraregional cost allocation method would be permitted.

2. Interregional Cost Allocation

170. An interregional transmission facility is one that in located within two or more transmission planning regions. In the past, most transmission upgrades

[168] As discussed above, the Commission proposes 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 may drive transmission needs.

[169] In addition, the Commission preliminarily finds that this principle does not affect the cross-border cost allocation methods developed by PJM and the Midwest ISO in response to Commission directives related to their intertwined configuration. *Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, at P 10 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,102 (2009).

[170] However, certain transmission developers may seek to participate in the regional transmission planning process only for coordination purposes (*e.g.,* to perform a reliability check for a participant-funded or merchant transmission project), in which case the transmission plan would not include a cost allocation for such projects.

were planned and constructed to meet the needs of customers within a given transmission planning region. However, new transmission facilities located within multiple transmission planning regions are now being considered by transmission providers in various parts of the nation. For example, as discussed above, development of renewable energy resources is increasing rapidly, in part in response to State renewable portfolio standard requirements. However, many of these resources are located far from load centers. New transmission facilities located within multiple transmission planning regions may be necessary to deliver the output of these renewable energy resources.

171. There are few rate structures in place today that provide for the allocation and recovery of costs of interregional transmission facilities. We are concerned that the absence of clear cost allocation rules for interregional transmission facilities could impede the development of such facilities, because of uncertainty regarding recovery of associated costs. In addition, the combined size of the multiple transmission planning regions in which an interregional facility would be located may increase the potential for both free ridership and the allocation of costs to those that receive no benefit from a facility.

172. Therefore, we propose to require that the public utility transmission providers located in each pair of neighboring transmission planning regions develop a mutually agreeable method for allocating between the two transmission planning regions the costs of a new transmission facility that is located within both regions and that is eligible for interregional cost recovery pursuant to the region's interregional transmission planning agreement developed in accordance with the requirement proposed above. In an RTO or ISO region, we propose that the method must be filed to become a part of the relevant tariffs. In other transmission planning regions, we propose that the cost allocation method be filed as part of the OATT of each public utility transmission provider in the region.

173. 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 for allocating the costs of a new interregional transmission facility. However, the Commission does not propose to require such agreements among more than two neighboring transmission planning regions.

174. Each cost allocation method filed in accordance with this proposal would be required to comply with the following 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.[171]

(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 facility.[172]

(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.

175. As with intraregional cost allocation, we are not proposing to require a uniform method of cost allocation for interregional transmission facilities. There may be legitimate reasons for the public utility transmission providers located in neighboring transmission planning regions to adopt different cost allocation methods. The Commission recognizes that several approaches to cost allocation may satisfy the proposed principles.[173]

176. Therefore, we propose to allow methods for allocating the costs of new interregional facilities to differ among pairs of transmission planning regions, as long as each method satisfies the proposed interregional cost allocation principles listed above. Moreover, 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 intraregional facilities. In addition, the cost allocation method used by the

[171] As discussed above, the Commission proposes 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 may drive transmission needs.

[172] 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.

[173] For the reasons discussed above with respect to cost allocation for intraregional transmission facilities, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, would not satisfy the proposed principles for interregional cost allocation.

public utility transmission providers located in a transmission planning region to allocate the costs of new intraregional 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.

177. Similar to our proposal for intraregional transmission facilities, we propose that if the public utility transmission providers in coordination with their customers and other stakeholders in a pair of neighboring transmission planning regions cannot agree on a cost allocation method for new interregional transmission facilities that satisfies these principles, then the Commission would use the record in the relevant compliance filing proceedings as a basis for applying the principles to develop an interregional cost allocation method that meets the Commission's requirements. Such a cost allocation method would not necessarily be the same for every pair of neighboring transmission planning regions that is unable to agree on a cost allocation method that satisfies the principles.

178. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment on the appropriateness and application of the proposed cost allocation principles with respect to new intraregional and interregional transmission facilities. If commenters believe that additional principles should apply to cost allocation for either intraregional or interregional transmission facilities, the Commission asks commenters to submit and explain the need for those principles.

VI. Compliance Filings

179. The Commission proposes that each public utility transmission provider must comply with the requirements of this Proposed Rule. With the exception of the proposed requirements with respect to interregional transmission planning agreements and an interregional cost allocation method or methods, the Commission proposes to 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 revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the proposed requirements set forth in this Proposed Rule.[174] The Commission proposes to 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 to demonstrate that it meets the proposed requirements set forth in the Proposed Rule with respect to interregional transmission planning agreements. The Commission proposes to 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 revising its OATT as necessary to demonstrate that it meets the proposed requirements set forth in this Proposed Rule with respect to an interregional cost allocation method or methods.

180. The Commission 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 this Proposed Rule.

181. The Commission proposes that transmission providers that are not public utilities would have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[175]

VII. Information Collection Statement

182. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[176] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[177] The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Burden Estimate: The estimated public reporting burdens for the proposed reporting requirements are as follows:

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 intraregional transmission planning process that meets transmission planning principles, includes consideration of public policy requirements, identifies and evaluates facilities to meet needs, develops cost allocation method, and produces an intraregional transmission plan that describes and incorporates a cost allocation method that meets the Commission's principles.	134	134	100 hrs. in Year 1; 50 hrs. in subsequent years.	13,400	6,700

[174] *See* Appendix B for the proposed *pro forma* Attachment K consistent with this NOPR.

[175] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63.

[176] 44 U.S.C. 3507(d).

[177] 5 CFR 1320.11.

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
Coordination, development, and filing with the Commission of interregional planning agreements that meet the Commission's requirements, that include consideration of public policy requirements, and that incorporate cost allocation methods that meets the Commission's principles; provide or post ongoing communications, and provide annual data exchange.	134	134	125 hrs. in Year 1; 50 hrs. in subsequent years.	16,750	6,700
Conforming tariff changes for local transmission planning, including those related to consideration of public policy requirements; and conforming tariff changes for intraregional and interregional planning.	134	134	50 hrs. in Year 1; 25 hours in subsequent years.	6,700	3,350
Total Estimated Additional Burden Hours, Proposed for FERC–917 in NOPR in RM10–23.	....	....	....	36,850	16,750

Cost To Comply: The Commission has projected costs of compliance for the reporting requirements as follows:

Year 1: $4,200,900 [36,850 hours × $114 per hour [178]]

Subsequent Years: $1,909,500 [or 16,750 hours × $114 per hour]

OMB's regulations require it to approve certain information collection requirements imposed by an agency rule. The Commission is submitting notification of this Proposed Rule to OMB. The Commission proposes to make the reporting requirements mandatory.

Title: FERC–917.

Action: Proposed Collection.

OMB Control No. 1902–0233.

Respondents: Electric Utility Transmission Providers. RTOs and ISOs also may file some materials on behalf of their members.

Frequency of responses: Initial filing and subsequent filings.

Necessity of the Information:

183. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission is proposing amendments to the *pro forma* OATT to correct certain deficiencies in transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this proposed rulemaking 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 and reasonable and not unduly discriminatory or preferential. We propose to achieve this goal by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

184. *Internal Review:* The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support associated with the information requirements.

185. Interested persons may obtain information on the 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: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873. For submitting comments concerning the collection of information and the associated burden estimate(s), please send your comments to the contact listed above and 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.* Please reference OMB Control No. 1902–0233 and the docket number of this proposed rulemaking in your submission.

VIII. Environmental Analysis

186. 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.[179] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[180]

IX. Regulatory Flexibility Act Analysis

187. The Regulatory Flexibility Act of 1980 (RFA) [181] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Proposed 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 estimated number of public utility transmission providers that, absent waiver, would have to modify their current OATTs by filing the revised pro

[178] 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).

[179] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[180] 18 CFR 380.4(a)(15).

[181] 5 U.S.C. 601–612.

forma OATT is 134. Of these public utility transmission providers, an estimated 10 filers, or 7.3% percent, have output of four million MWh or less per year.[182] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to 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 the proposed rule will not have a significant economic impact on a substantial number of small entities.

X. Comment Procedures

188. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days from publication in the **Federal Register**. Comments must refer to Docket No. RM10–23–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

189. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

190. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426.

191. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

[182] 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 7.3% of the filers are "small."

XI. Document Availability

192. 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 FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

193. From FERC'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.

194. User assistance is available for eLibrary and the FERC'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.*

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Moeller is concurring with a separate statement attached.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend 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. Paragraph (c)(1) introductory text and (c)(1)(i) through (c)(1)(iii) are revised.

b. Paragraph (c)(1)(vi) is revised.

c. Paragraphs (c)(3) introductory text, (c)(3)(i), and (c)(3)(ii) are revised.

d. Paragraph (c)(4) is revised.

e. Paragraph (d) (1) is revised.

f. Paragraph (e)(1) introductory text, 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. ___, FERC Stats. & Regs. ¶ ___ (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. ___, FERC Stats. & Regs. ¶ ___.

(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. ___, FERC Stats. & Regs. ¶ ___, 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 [60 days after date of publication of the Final Rule in the **Federal Register**], 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.___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs ¶ ___.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of [60 days after date of publication of the Final Rule in the **Federal Register**], 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. ___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs. ¶ ___.

* * * * *

(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. ___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs. ¶ ___.

(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 [60 days after date of publication of the Final Rule in the **Federal Register**], 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 [60 days after date of publication of the Final Rule in the **Federal Register**], 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.___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs ¶ ___.

* * * * *

(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. ___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs. ¶ ___.

(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. ___, FERC Stats. & Regs. ¶ ___, 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. ___, FERC Stats. & Regs. ¶ ___.

(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. ___, FERC Stats. & Regs. ¶ ___, 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., FERC Stats. & Regs. ¶ ___.

(d) *Waivers.* * * *

(1) No later than [60 days after date of publication of the Final Rule in the **Federal Register**], or

* * * * *

(e) *Non-public utility procedures for tariff reciprocity compliance.*

(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. ___, FERC Stats. & Regs. ¶ ___.

* * * * *

Note: The following appendices will not be published in the *Code of Federal Regulations.*

APPENDIX A—LIST OF SHORT NAMES OF COMMENTERS ON THE FEDERAL ENERGY REGULATORY COMMISSION'S NOTICE OF REQUEST FOR COMMENTS ON TRANSMISSION PLANNING PROCESSES UNDER ORDER NO. 890—DOCKET NO. AD09–8–000, OCTOBER 2009

Short name or acronym	Commenter
3M	3M Company, High Capacity Conductors.
AEP	American Electric Power Service Corporation.
Alabama PSC	Alabama Public Service Commission.
Allegheny Companies	Allegheny Power and Trans-Allegheny Interstate Line Company.
Ameren	Ameren Services Company.
American Antitrust Institute	American Antitrust Institute.
American Forest and Paper	American Forest & Paper Association.
American Transmission	American Transmission Company LLC.
APPA	American Public Power Association.
AREVA T&D	AREVA T&D Inc.

APPENDIX A—LIST OF SHORT NAMES OF COMMENTERS ON THE FEDERAL ENERGY REGULATORY COMMISSION'S NOTICE OF REQUEST FOR COMMENTS ON TRANSMISSION PLANNING PROCESSES UNDER ORDER NO. 890—DOCKET NO. AD09–8–000, OCTOBER 2009—Continued

Short name or acronym	Commenter
AWEA	American Wind Energy Association.
Baltimore Gas and Electric	Baltimore Gas and Electric Company.
Barbara Luchsinger	Barbara Luchsinger.
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
The Brattle Group	Peter Fox-Penner, Johannes Pfeifenberger, and Delphine Hou.
California ISO	California Independent System Operator Corporation.
Californians for Renewable Energy	Californians for Renewable Energy, Inc.
California PUC	California Public Utilities Commission.
California State Water Project	California Department of Water Resources State Water Project.
Calvin Daniels	Calvin Daniels.
Chinook and Zephyr	Chinook Power Transmission, LLC and Zephyr Power Transmission, LLC.
Clean Line	Clean Line Energy Partners, LLC.
Coalition To Advance Renewable Energy Through Bulk Energy Storage	Coalition To Advance Renewable Energy Through Bulk Energy Storage.
ColumbiaGrid	ColumbiaGrid.
Consolidated Edison, et al.	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
Dayton Power and Light	Dayton Power and Light Company.
Delaware Municipal and Southwestern Electric	Delaware Municipal Electric Corporation, Inc. and Southwestern Electric Cooperative, Inc.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
Eastern Interconnection Planning Collaborative Analysis Team	Eastern Interconnection Planning Collaborative Analysis Team.
Eastern PJM Governors	Governors of New Jersey, Delaware, Maryland, and Virginia.
EEI	Edison Electric Institute.
Electricity Consumers Resource Council	Electricity Consumers Resource Council.
ENE (Environment Northeast)	ENE Environment Northeast.
Energy Future Coalition	Energy Future Coalition.
Entergy	Entergy Services, Inc.
E.ON	E.ON U.S. LLC.
E.ON Climate & Renewables North America	E.ON Climate & Renewables North America.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Federal Trade Commission	Federal Trade Commission.
FirstEnergy	FirstEnergy Affiliates.
Florida Transmission Providers	Florida Power & Light, Progress Energy Florida, Tampa Electric Company, and JEA.
Georgia Transmission Corporation	Georgia Transmission Corporation.
Great River Energy	Great River Energy.
Green Energy Express	Green Energy Express, LLC.
Illinois Commission	Illinois Commerce Commission.
Imperial Irrigation District	Imperial Irrigation District (CA).
Independent Power Producers Coalition-West	Independent Power Producers Coalition-West.
Indicated Partners	Green Energy Express LLC; Transmission Technology Solutions LLC; SouthWestern Power Group II, LLC; Nevada Hydro Company; LS Power Transmission, LLC; and Pattern Transmission LP.
Integrys, et al.	Wisconsin Public Service Corporation, Upper Peninsula Power Company, and Integrys Energy Services, Inc.
ISO New England	ISO New England Inc.
ITC Holdings	ITC Holdings Corp.
Kelson Companies	Cottonwood Energy Company LP; Dogwood Energy LLC; and Magnolia Energy LP.
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; 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, et al.	Long Island Power Authority, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc.
Lorraine Fleming	Lorraine Fleming.
LS Power	LS Power Transmission, LLC.

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Short name or acronym	Commenter
Maine PUC and Public Advocate	Maine Public Utilities Commission and the Maine Office of the Public Advocate.
Massachusetts Attorney General	Massachusetts Attorney General.
Massachusetts Departments	Massachusetts Department of Public Utilities and Massachusetts Department of Energy Resources.
MEAG Power	MEAG Power.
MidAmerican	MidAmerican Energy Holdings Company.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
Midwest ISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Co., and Illinois Power Company); City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light 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; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
Modesto Irrigation District	Modesto Irrigation District.
NARUC	National Association of Regulatory Utility Commissioners.
National Audubon Society, et al.	National Audubon Society; Conservation Law Foundation; Energy Future Coalition; ENE (Environment Northeast); Environmental Defense Fund; Natural Resources Defense Council; Piedmont Environmental Council; Sierra Club; Sustainable FERC Project; and Union of Concerned Scientists.
National Grid	National Grid USA.
National Nuclear Security Administration Service Center	National Nuclear Security Administration Service Center in Albuquerque, New Mexico.
National Rural Electric Coops	National Rural Electric Cooperative Association.
NationalWind	NationalWind.
NEPOOL Participants	New England Power Pool Participants Committee.
Nevada Hydro	Nevada Hydro Company, Inc.
New England Clean Energy Council	New England Clean Energy Council.
New England States' Committee on Electricity	New England States' Committee on Electricity.
New Jersey Board	New Jersey Board of Public Utilities.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
NextEra	NextEra Energy Resources, LLC.
Northeast Utilities	Northeast Utilities Service Company.
Northern Tier Transmission Group	Northern Tier Transmission Group.
Northwest State Commissions and Consumer Counsel	Idaho Public Utilities Commission, Montana Consumer Counsel, Montana Public Service Commission, Public Utility Commission of Oregon, Utah Public Service Commission, and Wyoming Public Service Commission.
NRG	NRG Energy, Inc.
Ohio Commission	Public Utilities Commission of Ohio.
Old Dominion	Old Dominion Electric Cooperative.
Organization of MISO States	Organization of MISO States.
Pacific Gas and Electric	Pacific Gas and Electric Company.
Pattern Transmission	Pattern Transmission LP.
Peter C. Luchsinger M.D.	Peter C. Luchsinger M.D.
PHI Companies	Pepco Holdings, Inc.; Potomac Electric and Power Company; Delmarva Power & Light Company; and Atlantic City Electric Company.
Pioneer Transmission	Pioneer Transmission, LLC.
PJM	PJM Interconnection, LLC.
PPL	PPL Electric Utilities Corporation.
Progress Energy	Progress Energy, Inc.
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC.

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Short name or acronym	Commenter
Public Interest Organizations & Renewable Energy Groups	Alliance for Clean Energy New York; American Wind Energy Association; Center for Energy Efficiency & Renewable Technologies; Citizens Utility Board of Wisconsin; Conservation Law Foundation; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; National Audubon Society; Natural Resources Defense Council; Northeast Energy Efficiency Partnerships; Northwest Energy Coalition; Office of the Ohio Consumers' Counsel; Pace Energy and Climate Center; Piedmont Environmental Council; Project for Sustainable FERC Energy Policy; Sierra Club; Southern Alliance for Clean Energy; Union of Concerned Scientists; Western Grid Group; and Wind on the Wires.
Public Power Council	Public Power Council.
Renewable Energy Systems Americas	Renewable Energy Systems Americas Inc.
RRI Energy	RRI Energy, Inc.
Salt River Project	Salt River Project Agricultural Improvement and Power District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Solar Energy Industries	Solar Energy Industries Association.
South Carolina Electric & Gas	South Carolina Electric & Gas Company.
Southern California Edison	Southern California Edison Company.
Southern Companies	Southern Company Services, Inc.
SPP	Southwest Power Pool, Inc.
Startrans	Startrans IO, LLC.
Starwood	Starwood Energy Group Global, LLC.
State Representative Sloan	State Representative Tom Sloan.
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC.
Trans-Elect	Trans-Elect Development 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, Old Dominion Electric Cooperative, and Seminole Electric Cooperative, Inc.
Upper Great Plains Transmission Coalition	Upper Great Plains Transmission Coalition.
WECC	Western Electricity Coordinating Council.
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 Colorado, 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.
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.
Xcel	Xcel Energy Services Inc.

Appendix B: Pro Forma Open Access Transmission Tariff

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 the Final Rule in Docket No. RM05–25–000: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also include the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by State or Federal laws or regulations consistent with the Final Rule in Docket No. RM10–23–000. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05–25–000.

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 and neighboring transmission providers;

(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 evaluating transmission projects proposed to achieve public policy requirements established by State or Federal laws or regulations; and

(ix) The relevant cost allocation method or methods.

Intraregional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission solutions 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 not be unduly discriminatory and must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable, as described in the Final Rule in Docket No. RM10–23–000. 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 the Final Rule in Docket No. RM05–25–000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process shall also include the procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by State or Federal laws or regulations consistent with the Final Rule in Docket No. RM10–23–000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05–25–000.

Nothing in the regional transmission planning process shall include an unduly discriminatory process for transmission project submission and selection. The regional transmission planning process shall provide on a not unduly discriminatory basis for the sponsor of a facility that is selected through the regional transmission planning process for inclusion in the regional transmission plan to have a right, consistent with State or local laws or regulations, to construct and own that facility and to recover the cost of that facility through the applicable regional cost allocation method.

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 transmission plan;

(v) The obligations of and methods for transmission customers to submit data;

(vi) The dispute resolution process;

(vii) The study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The procedures and mechanisms for evaluating transmission projects proposed to achieve public policy requirements established by State or Federal laws or regulations; and

(ix) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six principles set forth in the final rule in Docket No. RM10–23–000.

Interregional Transmission Planning

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 issues related to interregional transmission facilities. This coordination between each pair of transmission planning regions must be reflected in an interregional transmission planning agreement filed with the Commission. The interregional transmission planning agreement 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 than separate intraregional transmission facilities.

The Transmission Provider must ensure that the following elements are included in any interregional transmission planning agreement in which it participates:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities;

(2) An agreement to exchange at least annually planning data and information;

(3) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six principles set forth in the final rule in Docket No. RM10–23–000.

United States of America Federal Energy Regulatory Commission

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

Docket No. RM10–23–000

Issued June 17, 2010.

MOELLER, Commissioner, *concurring:*

As I have repeatedly stressed in my years on this Commission, promoting investment in our nation's transmission infrastructure has been my top policy priority.[1] Robust electric transmission infrastructure is the ultimate "enabling" energy technology, as it can provide a more efficient electric system, enhanced reliability, increased access to less expensive and often cleaner resources, and the ability to harness location-constrained renewable resources. Conversely, the lack of adequate transmission investments often disproportionately raises consumer rates due to congestion, threatens the reliability of the nation's bulk power system, and increases reliance on older and dirtier generating resources.

While I am not certain that every policy in this proposed rule will ultimately be adopted, I am certain that building needed transmission lines is often the lowest-cost way to improve the delivery of electricity service. Although the Commission could have addressed regional cost allocation several years ago when it first became apparent that the organized markets were not reaching consensus on the issue, that wait is over and the Commission is now considering specific proposals to resolve cost allocation.

Given that the U.S. Congress is examining cost allocation at this time, our issuance of this proposed rule comes at a potentially sensitive time. While Congress is now considering several measures that deal directly with issues addressed in this proposed rule, I expect that this Commission will defer to the legislative branch as we move forward in our deliberations. This proposed rule, and the comments to follow, will provide the Congress with the

[1] *NSTAR Elec. Co.,* 125 FERC ¶ 61,313 (2008) (Moeller, Comm'r, dissenting in part) ("* * * the Commission should do what it can to encourage capital investment in needed transmission infrastructure projects."); *Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana,* 125 FERC ¶ 61,250 (2008) (Moeller, Comm'r, dissenting) ("* * * now is not the time for this Commission to discourage investment in needed transmission infrastructure."); *New York Indep. Sys. Operator, Inc.,* 129 FERC ¶ 61,045 (2009) (Moeller, Comm'r, dissenting) ("The main issue here is whether needed transmission is being built * * * I have encouraged investment in transmission infrastructure * * *"); *Southern California Edison Co.,* 129 FERC ¶ 61,013 (2009) (Moeller, Comm'r, dissenting in part) ("The transmission that is needed in this nation will not be built unless the companies that build it can attract adequate investment dollars.")

framework of the issues that we consider relevant and the opportunity for Congress to provide further guidance to us. Thus, our action today is not intended to interfere with that process, but rather to add helpful information and evidence that will be useful in the formation of Federal legislation.

Also controversial will be the question of whether incumbent utilities should retain rights of first refusal that were created under the Commission's jurisdiction. Alas, the question of whether transmission developers can compete on par with an incumbent transmission-owning utility is no longer theoretical. In recent cases, the Commission has been confronted with particular situations where competitors could be discouraged (or altogether blocked) from building a transmission project if the incumbent utility retains the right of first refusal.[2] While initial rulings have been rendered in these cases, the generic issue is ready for further discussion in this rulemaking.

Resolving controversial issues is rarely easy and I expect today's proposed rule to be both lauded and criticized. The changes proposed here are significant, but the future success of the organized markets and the nation's electric transmission system depend on resolving these long-debated and controversial issues.

[2] *Primary Power, LLC,* 131 FERC ¶ 61,015 (2010) (reh'g pending) and *Cent. Transmission, LLC* v. *PJM Interconnection L.L.C.,* 131 FERC ¶ 61,243 (2010).

Staff's efforts here have resulted in a proposal that will lead to a much needed conversation on how to best encourage needed capital investment. This will not be an easy matter to address when it comes before the Commission for a vote on the final rule, and for that reason this Commission should carefully consider the comments that we will receive. I will do my part to ensure that this Commission does not lose sight of the ultimate goal: A final rule that results in needed capital investment.

D. Moeller,
Commissioner.

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