

QUÉBEC

RÉGIE DE L'ÉNERGIE

**R-3669-2008
Phase 2**

**HYDRO-QUÉBEC
Demanderesse**

et

Intervenants

**COMPENDIUM DE LA PREUVE ET DES AUTORITÉS
THÈME 3
PROCESSUS DE PLANIFICATION
DES INSTALLATIONS DE TRANSPORT
(VOLUME 1 DE 2)**

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Montréal, ce 27 juin 2011

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**ORDONNANCE N° 890
DE LA
FEDERAL ENERGY REGULATORY COMMISSION**

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Sudeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Preventing Undue Discrimination and Preference in
Transmission Service

Docket Nos. RM05-17-000
RM05-25-000

ORDER NO. 890

FINAL RULE

(Issued February 16, 2007)

I. Introduction

1. This Final Rule addresses and remedies opportunities for undue discrimination under the pro forma Open Access Transmission Tariff (OATT) adopted in 1996 by Order No. 888.¹ This landmark rulemaking fostered greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In the ten

¹ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), 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) (TAPS v. FERC), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

years since Order No. 888, however, the Commission has found that the OATT contains flaws that undermine realizing its core objective of remedying undue discrimination. In the Notice of Proposed Rulemaking (NOPR) issued on May 19, 2006, the Commission proposed to remedy those flaws.² After receiving approximately 6,500 pages of comments from close to 300 parties, we now take final action. We highlight below the most critical reforms being adopted today.

2. First, the Final Rule will increase nondiscriminatory access to the grid by eliminating the wide discretion that transmission providers currently have in calculating available transfer capability (ATC).³ The calculation of ATC is one of the most critical functions under the OATT because it determines whether transmission customers can access alternative power supplies. Despite this, the existing OATT does not prescribe how ATC should be calculated because the Commission sought to rely on voluntary efforts by the industry to develop consistent methods of ATC calculation. This voluntary industry effort has not proven successful. The Commission therefore acts today to require public utilities, working through the North American Electric Reliability

² Preventing Undue Discrimination and Preference in Transmission Service, Notice of Proposed Rulemaking, 71 FR 32,636 (Jun. 6, 2006), FERC Stats. & Regs. ¶ 32,603 (2006).

³ The Commission used the term "Available Transmission Capability" in Order No. 888 to describe the amount of additional capability available in the transmission network to accommodate additional requests for transmission services. To be consistent with the term generally accepted throughout the industry, the Commission revises the pro forma OATT to adopt the term "Available Transfer Capability."

Corporation (NERC), to develop consistent methodologies for ATC calculation and to publish those methodologies to increase transparency. This important reform will eliminate the wide discretion that exists today in calculating ATC and ensure that customers are treated fairly in seeking alternative power supplies.

3. Second, the Final Rule will increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process. Transmission planning is a critical function under the pro forma OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans are developed. These deficiencies are serious, given the substantial need for new infrastructure in this Nation.⁴ We act today to remedy these deficiencies by requiring

⁴ Congress placed special emphasis on the development of transmission infrastructure, including the consideration of advanced transmission technologies, in the Energy Policy Act of 2005 (EPA 2005). See Pub. L. No. 109-58, 119 Stat. 594 (to be codified in scattered titles of the U.S.C.). The Commission has taken steps to implement that goal in numerous contexts, including recent rulemaking proceedings that address the promotion of transmission investment through pricing reform and the siting of certain transmission facilities. See Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), order on reh'g, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007), reh'g pending; Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, Order No. 689, 71 FR 69440 (Dec. 1, 2006), FERC

(continued)

transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.

4. Third, the Final Rule will also increase the efficient utilization of transmission by eliminating artificial barriers to use of the grid. The existing pro forma OATT allows a transmission provider to deny a request for long-term point-to-point service if the request cannot be satisfied in only one hour of the requested term. This practice discourages the efficient use of the existing grid and precludes access to alternative power supplies. We reform this practice by requiring that a conditional firm option be offered to customers seeking long-term point-to-point service, i.e., conditional firm service. We also modify the redispatch obligations of transmission providers to increase the efficient utilization of the grid, while also ensuring that reliability to native load customers is maintained.

5. Fourth, by adopting these and other reforms, the Final Rule facilitates the use of clean energy resources such as wind power. Conditional firm service is particularly important to wind resources that can provide significant economic and environmental value even if curtailed under limited circumstances. Open and coordinated transmission planning will enhance the ability of customers to access clean energy resources as part of

Stats. & Regs. ¶ 31,234 (2006), reh'g pending. As discussed herein, several actions taken in this Final Rule also relate to the need for investments in transmission infrastructure and are consistent with the Commission's responsibilities under EPAAct 2005.

their future resource portfolio. The Final Rule also benefits clean energy resources by reforming energy and generator imbalance charges. These reforms are particularly important to intermittent resources such as wind power because these resources have limited ability to control their output and, hence, must be assured that imbalance charges are no more than required to provide appropriate incentives for prudent behavior.

6. Fifth, the Final Rule will strengthen compliance and enforcement efforts. We are increasing the transparency of pro forma OATT administration, thereby increasing the ability of customers and our Office of Enforcement to detect undue discrimination. We are adopting operational penalties for clear violations of an OATT, thereby enhancing compliance while also reducing the burdens on our Office of Enforcement. We are also increasing the clarity of many other OATT requirements, thereby facilitating compliance by transmission providers with our regulations. This Final Rule thus reflects the close integration of our Office of Enforcement into policy development at the Commission. Several of the reforms we adopt today are informed by our experience with OATT administration through oversight, audits, and investigations performed by the Office of Enforcement.

7. Finally, we modify and improve several provisions of the pro forma OATT using our experience over the past ten years and clarify others that have proven ambiguous. For example, we reform our rollover rights policy to ensure that the rights and obligations of rollover customers are consistent with the resulting obligations of transmission providers to plan and upgrade the system to accommodate rollovers. We remove the

price cap on reassigned capacity because it is not necessary to remedy market power and doing so will otherwise increase the efficient use of existing capacity. We increase the efficient use of existing capacity by providing a priority to certain “pre-confirmed” requests for service. We increase certainty by providing greater clarity regarding the wholesale contracts that qualify as network resources. We also adopt numerous clarifications that should assist transmission providers and customers in implementing and using the pro forma OATT

8. Our actions in this proceeding have been informed to a great extent by the comments received in response to our notices of inquiry in the above-captioned dockets and the subsequent NOPR.⁵ We appreciate the time and thoughtfulness of all sectors of the industry in preparing comments. We have found them very informative and useful in reaching our decisions in this Final Rule.

II. Background

A. Historical Antecedent

9. In the NOPR, the Commission explained the historical background that led up to the issuance of Order No. 888, and the initiation of this rulemaking proceeding. We repeat that history here to place in context the actions we take today.

⁵ Preventing Undue Discrimination and Preference in Transmission Services, Notice of Inquiry, 112 FERC ¶ 61,299 (2005) (NOI); Information Requirements for Available Transfer Capability, Notice of Inquiry, 111 FERC ¶ 61,274 (2005) (ATC NOI).

energy, capacity and ancillary services. The Commission established an open, collaborative process that relied on voluntary regional participation to design RTOs tailored to the specific needs of each region. The Commission noted, however, that “[i]f the industry fails to form RTOs under this approach, the Commission will reconsider what further regulatory steps are in the public interest.”²⁶

21. Following Order No. 2000, RTOs were approved in several regions of the country including the Northeast (PJM; ISO New England),²⁷ the Midwest (MISO) and the South (SPP). In most cases, RTOs have assumed responsibility for calculating ATC across the footprint of the RTO, as well as the planning and expansion of the transmission grid, at least for facilities necessary for maintaining system reliability. However, large areas of the Nation have not developed RTOs using the voluntary structure adopted by the Commission in Order No. 2000. Moreover, transmission customers have complained that even in RTO markets there are instances when comparable transmission service is not provided, particularly in the area of transmission planning.

C. EPAcT 2005 and Recent Developments

22. Enacted on August 8, 2005, EPAcT added a number of new authorities and priorities for the Commission and emphasized certain of its existing obligations. Among other things, EPAcT 2005 recognized the importance of adequate transmission

²⁶ Id. at 30,993.

²⁷ A list of commenter acronyms can be found in Appendix B.

infrastructure development and its role in facilitating the development of competitive wholesale markets. The Congressional directives in EAct 2005 are intended to reverse the decline in transmission infrastructure investment. For example, Congress required the Commission to adopt a rule establishing incentive ratemaking for transmission infrastructure to help promote reliability and reduce congestion.²⁸ Congress also directed the Commission to encourage the deployment of advanced technologies.²⁹ Congress further directed the Commission to “exercise its authority” under EAct 2005 “in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities.”³⁰ Congress also gave the Commission certain “backstop” transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.³¹ EAct 2005 also authorized the Commission to require unregulated transmitting utilities (except for certain small entities)

²⁸ EAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s).

²⁹ EAct 2005 sec. 1223 (to be codified at 42 U.S.C. 16422). Indeed, Congress provided specific guidance as to the types of advanced technologies that should be encouraged in infrastructure improvements to include, among others, optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring. *Id.*

³⁰ EAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q).

³¹ EAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p).

to provide access to their transmission facilities on a comparable basis.³² Congress further ordered the Department of Energy (DOE) to study the benefits of economic dispatch and required the Commission to convene regional joint boards to develop a report to Congress containing recommendations for the use of security constrained economic dispatch within each region.³³ Congress also directed the Commission to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers, and it authorized the Commission to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric energy and transmission service.³⁴ Finally, Congress emphasized compliance with the Commission's regulations, adopting and

³² EPCA 2005 sec. 1231 (to be codified at section 211A of the FPA, 16 U.S.C. 824j-1).

³³ EPCA 2005 sec. 1234 (to be codified at 42 U.S.C. 16432); EPCA 2005 sec. 1298 (to be codified at section 223 of the FPA, 16 U.S.C. 824w). EPCA 2005 sec. 1234(b) defined economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

³⁴ EPCA 2005 sec. 1281 (to be codified at section 220 of the FPA, 16 U.S.C. 824t).

increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.³⁵

23. Recognizing the need for reform of Order No. 888 in light of the Commission's continuing concern regarding whether the pro forma OATT adequately remedies undue discrimination, the Commission issued an NOI on September 16, 2005³⁶ seeking comments on appropriate reforms of the Order No. 888 pro forma OATT. In the NOI, the Commission expressed its preliminary view that reforms to the pro forma OATT and public utilities' OATTs are necessary to avoid undue discrimination or preference in the provision of transmission service. The NOI sought comments on how best to accomplish the Commission's goals, specifically with respect to enhancements that are needed to (1) remedy any unduly discriminatory or preferential application of the pro forma OATT or (2) improve the clarity of the Order No. 888 pro forma OATT and the individual public utility tariffs in order to more readily identify violations and facilitate compliance.

24. The Commission received over 4,000 pages of initial and reply comments on the NOI. Based on these comments, the comments submitted in response to the ATC NOI,³⁷ our experience in implementing Order No. 888, and the changes in the industry since we

³⁵ EPCA 2005 sec. 1284(d) (to be codified at section 316 of the FPA, 16 U.S.C. 825o); EPCA 2005 sec. 1284(e) (to be codified at section 316A of the FPA, 16 U.S.C. 825o-1).

³⁶ See supra note 5.

³⁷ Id.

adopted it, the Commission proposed to reform the pro forma OATT in a number of ways. The Commission issued the NOPR on May 19, 2006 proposing a number of reforms aimed at remedying undue discrimination in the provision of open access transmission service and improving the clarity of the pro forma OATT and the individual tariffs of transmission providers in order to more readily identify violations and facilitate compliance. The Commission received over 5,700 pages of initial and reply comments in response. In response to comments on the particular issue of redispatch and conditional firm service (discussed in more detail below), the Commission issued a Notice of Request for Supplemental Comments on November 15, 2006,³⁸ that resulted in receipt of an additional 750 pages of comments.

25. Based on this voluminous record, the Commission concludes that reform of the pro forma OATT and associated amendments to its regulations are necessary to reduce the potential for undue discrimination and provide clarity in the obligations of transmission providers and customers alike. We turn next to a more complete explanation of this need for reform.

³⁸ Preventing Undue Discrimination and Preference in Transmission Service, 117 FERC ¶ 61,185 (2006).

III. Need for Reform of Order No. 888

A. Opportunities for Undue Discrimination Continue to Exist

26. Although Order No. 888 has been successful in many important respects, the need for reform of the Order No. 888 pro forma OATT has been apparent for some time. In 1999, the Commission held, in adopting Order No. 2000, that the pro forma OATT could not fully remedy undue discrimination because transmission providers retained both the incentive and the ability to discriminate against third parties, particularly in areas where the pro forma OATT left the transmission provider with significant discretion.³⁹ The Commission made a similar finding in Order No. 2003,⁴⁰ holding that opportunities for undue discrimination continue to exist in areas where the pro forma OATT leaves transmission providers with substantial discretion.⁴¹ The NOPR reaffirmed these findings, preliminarily concluding that opportunities for undue discrimination continue to exist in the provision of open access transmission service. The Commission therefore

³⁹ Order No. 2000 at 31,105.

⁴⁰ See Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 at P 11-12 (2003), order on reh'g, Order No. 2003-A, 69 FR 15932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), order on reh'g, Order No. 2003-B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, 70 FR 37,661 (Jun. 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC, No. 04-1148, 2007 U.S. App. LEXIS 626 (D.C. Cir. Jan. 12, 2007).

⁴¹ Order No. 2003 at P 11-12.

filed by transmission customers or other parties. Case-by-case application of the reforms adopted in this Final Rule would be inappropriate since the most fundamental problems addressed here arise from deficiencies in the pro forma OATT itself, not simply the implementation of the pro forma OATT by a few transmission providers. Also, we decline to establish a one-year review period for the reformed pro forma OATT, as EPSA recommends. The Commission will continue to actively monitor compliance with its orders and, as necessary, institute further proceedings to meet its statutory obligation to remedy undue discrimination.

43. The Commission will not catalog each and every basis for its reform of the pro forma OATT in this section. Rather, we identify the bases for some of the most fundamental reforms herein and, in addition, we explain in each individual section of the Final Rule the inadequacies of the existing pro forma OATT provisions being addressed there and the reasons why our reforms are necessary to remedy undue discrimination or otherwise provide for rates, terms and conditions of service under the pro forma OATT that are just and reasonable.

B. Lack of Transparency Undermines Confidence in Open Access and Impedes Enforcement of Open Access Requirements

44. Following the issuance of the NOI, the Commission received a number of comments asserting that increased transparency would aid transmission customers in their participation in the wholesale market. A common theme in the comments was that a lack of transparency could lead to claims of discrimination and could make such claims more

difficult to resolve. Commenters urged the Commission to improve transparency in a number of areas, particularly the evaluation of ATC and the planning of the transmission system, as well as the processing of transmission service requests and studies.

45. In the NOPR, the Commission agreed that a lack of transparency both increases the potential for undue discrimination and makes it more difficult to detect. The Commission reasoned that this lack of sufficient transparency was caused in part by inadequate compliance with the existing OASIS regulations and in part by inadequate transparency requirements. The Commission stated that the proposed reforms were intended to address both elements of the problem in an effort to increase confidence in open access tariffs and to facilitate compliance with the Commission's regulations and its enforcement of them.

Comments

46. Williams states that its interests have been consistently and significantly compromised by the discretion afforded transmission providers in the interpretation of the OATT and the lack of transparency in requesting, scheduling and interrupting of transmission service. According to Williams, simply being told that service is being curtailed for reliability purposes under opaque local procedures, in the absence of a NERC Transmission Loading Relief (TLR) event, leaves market participants suffering the consequences without knowing on what basis the decision was reached, and without assurance that the decision was made in a non-discriminatory manner. Ultimately, Williams adds, the lack of transparency and latitude taken by the transmission provider to

determine which requests for service are confirmed or denied and which are curtailed or interrupted in real time frustrates the Commission's goal of preventing undue discrimination and preference in the provision of transmission service. Furthermore, Williams states, the same lack of transparency exists around the opaque processes utilized, assumptions made, and basis on which the results of transmission planning studies are conducted to grant or deny requests for service.

47. APPA agrees that additional transparency in the administration of public utility transmission providers' OATTs will be of material assistance to both the Commission and transmission customers. However, APPA argues that the Commission must go beyond increasing transparency in the administration of public utility transmission providers' OATTs. According to APPA, more transparency will not change the basic industry paradigm with transmission customers depending on monopoly transmission providers for service. In APPA's view, customers are often reluctant to file complaints or bring problems to the Commission's attention because they depend on their transmission providers' systems for the vital services they need to serve their loads. APPA argues that the Commission not only has an obligation to act to remedy undue discrimination when it sees it, but also has an affirmative duty to look for it. According to APPA, the Commission must continue to actively regulate the transmission services that public utility transmission providers offer, even if full transparency is achieved through the revisions to the OATT implemented in the instant docket.

48. EPSC agrees that greater transparency will help enable market participants and the Commission to monitor and audit the behavior of transmission providers. EPSC states that the several “black boxes” shielding discriminatory transmission service over the past ten years must be opened. However, EPSC argues, there must be meaningful clarity and obligations set out in the rules and OATT requirements – transparency simply for the sake of knowing why transmission service has been denied only illuminates a “bridge to nowhere” and fails to satisfy the Federal Power Act.

49. Entergy also supports the Commission’s efforts to provide greater clarity in the rights and obligations of transmission providers and transmission customers under the OATT. According to Entergy, many of the improvements proposed by the Commission will reduce the likelihood of disputes and promote greater confidence on the part of customers that they are being treated fairly. Entergy states that, while it recognizes that the lack of clarity makes it difficult for the Commission to detect instances of non-compliance by transmission providers, Entergy also believes that this lack of clarity often makes it easier for transmission customers to convert every practice or policy into a claim of discrimination or other misconduct.

50. Although not convinced that there is a compelling need for increased transparency since transmission providers are already required to disclose voluminous amounts of information, Southern states that it recognizes that some reforms in the availability of information may be advantageous. However, Southern asserts, providing additional transparency must not simply impose additional reporting requirements; any such

transparency-related reforms should be made after taking into consideration the extent and type of data and information that is already provided.

Commission Determination

51. The Commission concludes that inadequate transparency requirements, combined with inadequate compliance with existing OASIS regulations, increases the opportunities for undue discrimination under the pro forma OATT and makes instances of undue discrimination more difficult to detect. We find that the reforms we adopt in this Final Rule will improve transparency in the OATT, reduce opportunities for undue discrimination, and increase our ability to detect undue discrimination.

C. Congestion and Inadequate Infrastructure Development Impede Customers' Use of the Grid

52. The Commission noted in the NOPR that the ability and incentive to discriminate increases as the transmission system becomes more congested. The Commission observed that the pro forma OATT contained only minimal requirements regarding transmission planning, which have proven to be inadequate as the Nation faces insufficient transmission investment in many areas. The Commission preliminarily concluded that the inadequacy of the existing obligation to conduct transmission system planning, coupled with the lack of transparency surrounding system planning generally, required reform of the pro forma OATT to ensure that transmission infrastructure is constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers. The Commission therefore proposed to

require public utilities to engage in an open and transparent planning process at both the local and regional levels.

Comments

53. APPA agrees that the lack of adequate transmission infrastructure is one of the core problems facing the electric utility industry. APPA supports revisions to the pro forma OATT to enhance and improve transmission planning on both an individual system and regional basis. Several commenters go further, arguing that the proposed reforms are insufficient and urging the Commission to more strongly encourage infrastructure development. EPSA asserts that successful implementation of the Congressional policy in favor of wholesale competition and state policies in favor of competitive procurement is frustrated by the lack of sufficient open access to the transmission grid. According to EPSA, new power plant investment is highly unlikely to occur, except by the transmission provider or its affiliate on a "sole source" or "no bid" basis (despite federal and state policies to the contrary), if unaffiliated suppliers cannot effectively and efficiently obtain transmission service. EPSA argues that failure to boldly reform the Commission's open access transmission rules at this critical juncture would effectively hand an undeserved victory to the very transmission providers who, by the Commission's own findings, have the motive and the opportunity to discriminate. International Transmission argues that tariff reform is no substitute for prudent investment in the transmission infrastructure needed to increase the underlying physical capability of the transmission system.

54. On the other hand, some commenters dispute the Commission's assertion in the NOPR that vertically-integrated utilities operating in non-RTO regions have an incentive to discriminate and, therefore, are not adequately expanding the transmission grid to accommodate new entry by more efficient competitors. New Mexico Attorney General argues that vertically-integrated utilities operating under the traditional rate-base, rate-of-return model of regulation in fact have been historically criticized for having incentives to overbuild. New Mexico Attorney General asserts that most transmission projects are in reality derailed by strong "NIMBY" opposition to the actual siting of transmission lines. Another countervailing factor to the utility's incentive to overbuild, in New Mexico Attorney General's view, is the fact that state regulators attempt to limit capacity investment to reasonable levels only necessary to serve native load.

55. Southern states that the Commission's assertion in the NOPR that vertically-integrated utilities do not have an incentive to expand the grid overlooks the fact that many such utilities are under state legal duties to procure generation supplies through open, non-discriminatory requests for proposals, with the winners of those requests for proposals often being competitors of the vertically-integrated utility. Southern maintains that the winning competitive generation is then integrated into the host utility's transmission system and dispatch, and the transmission system is expanded to ensure the deliverability of this competitive generation. Furthermore, Southern states, a competitive generator can also have the output of its generator planned into the transmission provider's system if it takes long-term firm service under the OATT, with the

transmission provider then being under a legal duty to expand its transmission system accordingly. Southern notes that it alone has invested \$3.2 billion in transmission over the past decade and plans to invest another \$2.8 billion over the next five years (2006-2010).

56. Community Power Alliance also argues that the Commission's own June 2005 "State of the Markets Report" contradicts the Commission's assertion that vertically-integrated utilities do not have the proper incentives to expand the grid. Community Power Alliance contends that this report shows that the amount of transmission investments made in the non-RTO regions, where vertically-integrated utilities typically operate, substantially exceeds the amount of transmission investments made in RTO regions.

Commission Determination

57. The Commission concludes that reforms are needed to ensure that transmission infrastructure is evaluated, and if needed, constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers. As noted above, vertically-integrated utilities do not have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors. Despite this, the existing pro forma OATT contains very few requirements regarding how transmission planning should be conducted to ensure that undue discrimination does not occur.

58. Our concern over this flaw is heightened by the critical need for new transmission infrastructure in this Nation. As the Commission explained in the NOPR, transmission capacity is being constructed at a much slower rate than the rate of increase in customer demand, with transmission capacity per MW of peak demand declining at an average rate of 2.1 percent per year during the period 1992 to 2002.⁵⁵ The projections suggest that this trend will continue through 2012.⁵⁶ As a result, there has been a significant decrease in transmission capacity relative to load in every NERC region.⁵⁷ In light of this trend, there is a compelling need to build new transmission and respond to increasing demand through other means. EEI estimates that capital spending must increase by 25 percent, from \$4 billion annually to \$5 billion annually, to ensure system reliability and to accommodate wholesale electric markets.⁵⁸ The legacy systems constructed by vertically-integrated utilities prior to the adoption of Order No. 888 support “only limited

⁵⁵ Eric Hirst, U.S. Transmission Capacity: Present Status and Future Prospects (Aug. 2004), http://www.eei.org/industry_issues/energy_infrastructure/transmission/USTransCapacity10-18-04.pdf (Present Status and Future Prospects).

⁵⁶ Present Status and Future Prospects at v.

⁵⁷ Brendan Kirby (Oak Ridge National Laboratory, U.S. Department of Energy), Barriers to Transmission Investment, Technical Conference Presentation, (Docket No. AD05-5-000) (April 22, 2005).

⁵⁸ Energy Policy Act of 2005: Hearings before the Subcommittee on Energy and Air Quality of the House Committee on Energy and Commerce, 109th Congress, First Sess. (2005) (Prepared statement of Thomas R. Kuhn, President of EEI).

amounts of inter-regional power flows and transactions. Thus, existing systems cannot fully support all of society's goals for a modern electric-power system."⁵⁹

59. Expansion of the transmission system, as well as more efficient use of the grid, will alleviate the growth of congestion in most regions of the country. Transmission congestion has created fairly small local load pockets in primarily urban areas, e.g., New York City, Long Island, Boston, parts of Connecticut, and the San Francisco Bay Area. Other load pocket concerns have arisen in parts of northern Virginia, and various load centers in SPP. Still other constraints are more regional in scope: from the Midwest to the Mid-Atlantic, from the Midwest to TVA, into and within California, from TVA and Southern into Entergy, from Mid-America Interconnected Network into Wisconsin-Upper Michigan Systems, and into Florida.

60. Transmission congestion can have significant cost impacts on consumers. In 2002, DOE issued a study estimating the costs of congestion in four U.S. regions: California, PJM, New York and New England.⁶⁰ DOE found that, despite the overall

⁵⁹ Present Status and Future Prospects at v.

⁶⁰ U.S. Department of Energy, National Transmission Grid Study at 11, 16-17 (May 2002), available at www.ferc.gov/industries/electric/indus-act/transmission-grid.pdf. To conduct this study, DOE estimated the benefits of interregional wholesale power markets using the Policy Office Electricity Modeling System (POEMS). POEMS is a national energy model designed specifically to examine the impacts of electricity restructuring. The model includes economic, regional, and temporal detail that is needed to analyze the economics of interregional trade. In the first step of the study, DOE used POEMS to examine the cost reductions that would occur if increased electricity transfers across congested paths were allowed in these four regions, assuming generators bid their

(continued)

savings of wholesale electricity markets that lowered consumers' electricity bills by nearly \$13 billion annually, interregional transmission congestion cost consumers hundreds of millions of dollars annually. DOE concluded that relieving bottlenecks in these four regions alone could save consumers about \$500 million annually.⁶¹ In 2006, DOE released another study identifying two areas of the country with severe existing or growing congestion problems: the Atlantic coastal area from metropolitan New York southward through Northern Virginia, and Southern California.⁶²

61. The decline in transmission investment and increase in transmission congestion underscore our concerns over inadequate planning provisions of the existing pro forma OATT. The existing pro forma OATT, as indicated above, contains very little specificity regarding how transmission planning should be conducted, how customers' needs are incorporated into that process, and what information is publicly available regarding the

marginal costs. Under this assumption, consumer costs declined by \$157 million per year. In the second step, DOE calculated the increase in congestion costs under the assumption that generators bid above their marginal operating costs when supplies are tight and additional electricity cannot be imported. The price spikes were assumed to occur during hours when at least one transmission link into a sub-region was congested and demand was greater than 90 percent of peak demand. When prices spike an additional \$50 per MWh (above the price predicted when generators bid their marginal operating cost) during these periods, congestion costs nearly double to \$300 million.

⁶¹ Id. at xi and ii.

⁶² U.S. Department of Energy, National Electric Transmission Congestion Study, Executive Summary at 2 (August 2006), available at <http://www.ferc.gov/industries/electric/indus-act/doe-congestion-study-2006.pdf>.

transmission providers' assumptions, criteria and data used in the planning process. These inadequacies are sufficiently severe, standing alone, to merit reform of the OATT. However, they are of even greater concern given the current state of the transmission grid. With inadequate levels of investment in the grid and increasing transmission congestion, customers' ability to access alternatives to the transmission provider's resources is limited. It is therefore imperative for the Commission to ensure that the planning process under each transmission provider's OATT is sufficient to prevent undue discrimination and transparent enough to detect any remaining instances of undue discrimination. We have done so in the reforms adopted and explained in section V.B.

D. A Consistent Method of Measuring ATC Is Needed

62. Another area in which transmission providers have significant discretion under the pro forma OATT is the calculation of ATC. While Order No. 888 obligated each public utility to calculate the amount of transfer capability on its system available for sale to third parties, the Commission did not standardize the methodology for calculating ATC, nor did it impose any specific requirements regarding the disclosure of the methodologies used by each transmission provider.⁶³ As a result, there are a variety of ATC calculation methodologies in use today and very few clear rules governing their use. Moreover, there is often very little transparency about the nature of these calculations, given that many

⁶³ Order No. 888 at 31,794 n.610.

posted on OASIS. As we explained in the Policy Statement on Enforcement, however, this new authority carries with it the responsibility to ensure that enforcement is firm but fair and that our rules are as clear as practicable to facilitate compliance.⁷⁵ We conclude that this Final Rule is fully consistent with these principles because it clarifies our rules, in many areas, which will facilitate compliance by transmission providers.

IV. Summary, Scope and Applicability of the Final Rule

82. This section provides a summary of the major components of the Final Rule, a description of the core elements of Order No. 888 that we retain, and a discussion of the applicability of the proposed rule to various entities.

A. Summary of Reforms

83. Consistency and transparency of ATC calculations. The Commission affirms the finding in the NOPR that the lack of a consistent, industry-wide methodology for calculating ATC, and the lack of adequate transparency in ATC calculations, increases the potential for undue discrimination and also makes undue discrimination more difficult to detect. The lack of consistent standards can facilitate undue discrimination by giving a transmission provider the discretion, and hence the ability and opportunity, to favor itself and its affiliates over third parties in how it calculates and allocates ATC. In this Final Rule, we give the industry specific guidance regarding the calculation of ATC and

⁷⁵ Enforcement of Statutes, Orders, Rules and Regulations, Policy Statement on Enforcement, 113 FERC ¶ 61,068 (2005) (Policy Statement on Enforcement).

establish a firm deadline to develop certain requirements to make more consistent the ATC calculation process and the process of exchanging data between transmission providers about ATC. In addition, we amend pro forma OATT requirements as well as our OASIS regulations to increase the transparency in how ATC is calculated.

84. Requirement for coordinated, open and transparent transmission planning. The Commission also affirms the finding in the NOPR that Order No. 888 does not contain sufficient protections to guard against undue discrimination in transmission system planning. Without adequate coordination and open participation, market participants have minimal input or insight into whether a particular transmission plan treats all loads and generators comparably. To ensure that truly comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we amend the pro forma OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level. To implement this remedy, we adopt the eight planning principles proposed in the NOPR, as well as one additional principle, that each public utility transmission provider will be required to follow. We recognize that many regions have made significant progress in recent years in creating greater openness and transparency in transmission planning and believe our proposed reforms will build upon, strengthen, and improve this progress to reform transmission planning.

85. Transmission Pricing Reforms. Consistent with the focus of Order No. 888 on the non-rate terms and conditions of open access, the Commission does not initiate broad reform of transmission pricing policy through this Final Rule. However, we have

identified several pricing rules that are part and parcel of OATT service that merit reform.

- Energy and Generator Imbalance Charges. We find that energy and generator imbalance charges we have previously accepted are excessive, too varied, and otherwise unrelated to the cost of providing the service and, therefore, we reform energy and generator imbalance pricing. We adopt tiered pro forma OATT energy and generator imbalance provisions similar to those in use by Bonneville and exempt intermittent resources from the highest deviation band. In these new provisions, imbalance charges are based on incremental cost and escalate as the imbalance increases. Any deviations from these provisions must be consistent with or superior to the pro forma OATT as modified by this Final Rule and must meet the following criteria: the charges must (1) be related to the cost of correcting the imbalance, (2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and (3) account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the deviation penalties.
- Capacity Reassignment Pricing. We find that the existing cap on the reassignment of point-to-point service is no longer just and reasonable and, therefore, we eliminate the cap. We believe that removing the cap will eliminate an unnecessary impediment to the resale of capacity, which in turn should increase utilization of

the grid and otherwise ensure that point-to-point service is just, reasonable, and not unduly discriminatory.

- Crediting of Customer-Owned Facilities. We retain most elements of our existing policy respecting the crediting of customer-owned facilities, including the requirement that such facilities meet the integration standard. However, we eliminate the requirement that new facilities can receive credits only if they are “jointly planned” because this requirement provides a disincentive to coordinated planning. Rather, we provide that such new facilities are eligible for credits if such facilities are integrated into the operations of the transmission provider’s facilities. Customer-owned facilities shall be presumed to be integrated if those facilities, if owned by the transmission provider, would be eligible for inclusion in the transmission provider’s annual transmission revenue requirement.

86. Improvements to Point-to-Point Service. The Commission concludes that the existing methods for evaluating requests for long-term firm point-to-point service are no longer just, reasonable, and not unduly discriminatory. The existing pro forma OATT allows the transmission provider to deny a request for long-term point-to-point service if that service is not available in a single hour of the period studied. We find that this approach is not comparable because, when a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be deliverable in a few hours of the year. To remedy this problem, the Commission adopts a “conditional firm” component to long-

term point-to-point service that addresses the situation where firm service can be provided for most, but not all, hours of the period requested. We also reform the existing requirements for the provision of redispatch service to ensure that they are of greater use to transmission customers and more consistent with reliability planning and operation of the system.

87. Reform of rollover rights. The Commission concludes that section 2.2 of the pro forma OATT, which grants an ongoing right to transmission customers to renew or “roll over” their contracts, should be reformed. The current rollover rights do not provide consistency between the rights of rollover customers and the resulting obligations of transmission providers to plan and upgrade the system to accommodate rollovers. The Commission therefore amends section 2.2 to ensure greater consistency with transmission planning and construction timelines and modifies the minimum term of the rollover rights to five years, rather than the current minimum term of one year. The Commission also requires that a transmission customer eligible for rollover rights provide notice of whether or not it will exercise its right of first refusal to renew the contract no less than one year before the expiration date of the transmission service agreement, rather than within the current 60-day period.

88. Increases in transparency to lessen the opportunities to discriminate and reduce transaction costs. In addition to the increased transparency we require regarding the calculation of ATC and transmission planning, we increase the transparency of transmission service provided under the pro forma OATT in several other respects. For

example, we require transmission providers and their network customers to use the transmission providers' OASIS to request designation of a new network resource and to terminate the designation of an existing network resource. In addition, we require transmission providers to modify their OASIS so that requests to designate and terminate a network resource can be queried, allowing all parties access to such information. We also require transmission providers to post a list of their current designated network resources and all network customers' current designated network resources on their OASIS. Finally, we require transmission providers to post on OASIS all their business rules, practices and standards that relate to transmission services provided under the pro forma OATT.

89. Strengthening enforcement of the pro forma OATT. The reforms adopted in this Final Rule provide greater clarity in the terms and conditions of the pro forma OATT, resolving ambiguities in the existing pro forma OATT that have made undue discrimination easier to accomplish and more difficult to detect. Our new civil penalty authority under EAct 2005 gives us ample power to remedy tariff violations, but it also places upon us an increased responsibility to make the rules as clear as possible. We fulfill that responsibility in the Final Rule by providing greater clarity where appropriate to several critical OATT provisions. We also adopt a number of posting and reporting requirements that will provide the Commission and market participants with information about each transmission provider's performance of pro forma OATT obligations. For example, we require transmission providers to post specific performance metrics related

to their completion of studies required under the pro forma OATT. We note that the Commission will continue to audit compliance with the pro forma OATT, and toward that end require transmission information kept on OASIS to be retained for audit purposes for five years. Finally, we adopt a number of reforms to operational penalties assessed under the pro forma OATT, including so-called “over-use” penalties and the treatment of operational penalty revenues collected from transmission providers and their affiliates.

90. Miscellaneous OATT improvements. Finally, we implement a number of improvements to the terms and conditions of the pro forma OATT to incorporate the lessons learned over the past ten years. We briefly note these below:

- Designation of network resources. We provide clarification regarding the types of agreements that may be designated as network resources, the process for verifying whether agreements meet the requirements in the pro forma OATT, and the requirement for transmission providers to designate and undesignate network resources. We also require customers to submit an attestation with each application to designate a new network resource.
- Reservation priorities. We change the priority rules to give certain priority to pre-confirmed transmission service requests submitted in the same time period. We also add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service.

- Clarifications related to network service. We provide clarification related to use of network service on an “as available basis” and to “redirects” of network service.

B. Core Elements of Order No. 888 That Are Retained

91. Although we are adopting many important reforms to Order No. 888 and the pro forma OATT in this Final Rule, we emphasize that many of the core elements of Order No. 888 are retained. As the Commission noted in the NOPR, many of these core elements enjoy broad support from many sectors of the industry. A variety of commenters – in response to the NOI issued earlier in this proceeding and again in response to the NOPR – have urged the Commission to focus on meaningful incremental reforms to the pro forma OATT, rather than on industry restructuring. We share the view that Order No. 888 can be strengthened without discarding its fundamental structure. We discuss below the core elements that are being retained and the comments received on these points.

1. Federal/State Jurisdiction

92. In Order No. 888, the Commission stated that it has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce.⁷⁶ Though the Commission adopted a test for determining what constitute Commission-jurisdictional transmission facilities and what constitute state-jurisdictional local

⁷⁶ Order No. 888 at 31,781.

C. Applicability of the Final Rule

1. Non-ISO/RTO Public Utility Transmission Providers

124. In the NOPR, the Commission proposed to apply the Final Rule to all public utility transmission providers, including those that are approved ISOs and RTOs. With respect to non-ISO/RTO transmission providers, the Commission proposed to require all such transmission providers to submit FPA section 206 compliance filings, within 60 days after the publication of the Final Rule in the Federal Register, that contain the non-rate terms and conditions set forth in the Final Rule. The Commission also acknowledged that certain non-rate terms and conditions, such as Attachment C (relating to the transmission provider's ATC calculation methodology) and Attachment K (relating to the transmission provider's transmission planning process), may require more than 60 days to prepare and sought comment on an appropriate time period in which to require the submission of these attachments.

125. Following their FPA section 206 compliance filings, the Commission proposed that transmission providers could submit filings under FPA section 205 proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the pro forma OATT.

Comments

126. Several commenters ask the Commission to clarify and/or revise the proposal for dealing with previously-approved provisions that depart from the existing

require that employees engaged in transmission functions operate separately from employees of energy affiliates and marketing affiliates. A number of information sharing restrictions also apply, which prohibit transmission providers from allowing employees of their energy and marketing affiliates to obtain access to transmission or customer information, except via OASIS.

123. The Commission aggressively enforces the Standards of Conduct and, as referenced by APPA, cooperates with state regulators to ensure that the functional unbundling regime is sufficient to prevent undue discrimination. The Commission's Office of Enforcement is well-suited to investigate potential violations of the Standards of Conduct and to propose remedies, including structural remedies if necessary, to ensure that the separation of functions and information restrictions are fully implemented. We believe that the increased clarity and transparency adopted in other parts of this Final Rule, when coupled with the Standards of Conduct rules and our rigorous enforcement program, will ensure that the functional unbundling requirement will serve its original purpose.

Order No. 2004-C, 70 FR 284 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,172 (2005), order on reh'g, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), vacated, National Fuel, 468 F.3d 831. The Commission has issued an interim rule promulgating temporary regulations consistent with the Court's decision and initiated a further rulemaking to propose permanent regulations. See Standards of Conduct for Transmission Providers, Order No. 690, 72 FR 2427 (Jan. 19, 2007), FERC Stats. & Regs. ¶ 31,327 (2007); Standards of Conduct for Transmission Providers, Notice of Proposed Rulemaking, 72 FR 3958 (Jan. 29, 2007), FERC Stats. & Regs. ¶ 32,611 (2007) (Standards of Conduct NOPR).

(Order No. 888) pro forma OATT. APPA contends that after this multi-phase rulemaking (NOI/NOPR/Final Rule) to revise the OATT, the Commission should hold those public utility transmission providers that propose non-rate terms and conditions differing from the new pro forma OATT to a high standard of proof under the “consistent with or superior to” standard. According to APPA, any non-rate term and condition that differs from the revised pro forma OATT should be “additive” in nature (for example, a new service offering, such as network contract demand service) or should propose substantive improvements in transmission service to customers. APPA argues that a public utility transmission provider should not be able to make an FPA section 206 compliance filing to implement the pro forma OATT and then “water down” its new OATT through an FPA section 205 filing that degrades its transmission service offerings or diminishes the quality of that service.

127. In its reply comments, APPA recommends that the Commission require non-ISO/RTO transmission providers to file the new pro forma OATT set out in the Final Rule and add in redline – either in that filing, or a companion one – all previously approved transmission provider-specific provisions. APPA states that transmission providers should then explain whether they propose to include these provisions in their revised OATTs, why they propose to retain or delete these provisions, and whether they believe these provisions are “affected by the revisions adopted in the Final Rule.”

128. In contrast, Duke and EEI ask the Commission to clarify that transmission providers with previously-approved departures from the OATT that are not related to the

reforms adopted in this Final Rule will not be required to rejustify these provisions in their FPA section 206 compliance filings. They also ask that transmission providers not be required first to adopt all of the provisions of the revised pro forma OATT and then make an FPA section 205 filing to refile a departure previously approved by the Commission. They recommend that existing, approved departures from the pro forma OATT that are not affected in a substantive way by the changes to the pro forma OATT should be included in the initial FPA section 206 filing.¹⁰⁴ On reply, Indianapolis Power agrees with Duke and EEI and urges the Commission to consider the unwieldy and cost prohibitive nature of a process that would require transmission providers to demonstrate that previously-accepted elements of their OATTs are acceptable.

129. Duke and EEI, in their reply comments, argue that APPA's approach would be inefficient and would cause a substantial disruption to transmission service because both transmission providers and transmission customers would be required to abandon tariff provisions that the Commission has previously found to be consistent with or superior to the pro forma OATT and that are regularly being used. For example, Duke notes, Duke Carolina has an Attachment K that covers the Independent Entity that will oversee the provision of transmission service by Duke. Duke asserts that a literal interpretation of the NOPR proposal would mean that it would have to delete this attachment and replace its

¹⁰⁴ Duke and EEI propose that a utility would redline its compliance filing OATT against the revised pro forma OATT so that the Commission can readily identify the "already-approved" differences.

entire OATT with the revised pro forma OATT and then refile its entire Independent Entity proposal with its FPA section 205 filing. Similarly, Entergy states that it currently has a pro forma Generator Imbalance Agreement in place that was agreed to by the IPPs on its system and accepted by the Commission. Entergy urges the Commission to permit transmission providers to propose their own imbalance pricing methodology as long as the proposed generator imbalance charges are consistent with or superior to the generator imbalance provisions ultimately adopted in the OATT.

130. On reply, NRECA opposes EEI's compliance proposal. NRECA states that the Commission should retain the two-phased compliance procedure proposed in the NOPR because it strikes a fair balance by providing transmission providers the opportunity to suggest changes to their pro forma OATTs under FPA section 205, while allowing transmission customers and others the opportunity to argue that the deviations from the new pro forma OATT are neither consistent with nor superior to the pro forma OATT.

131. NRECA acknowledges that there will be a burden on the transmission provider to prepare a compliance filing; however, it urges the Commission to retain its proposal and require transmission providers to identify those terms and conditions that differ from the pro forma OATT. NRECA agrees that, if a term or condition unrelated to any modification of the pro forma OATT in the instant rulemaking has already been found to be consistent with or superior to the existing Order No. 888 pro forma OATT, it likely continues to be consistent with or superior to the revised pro forma OATT term or condition. NRECA argues, however, that a public utility transmission provider should

still be required in a compliance filing to identify these deviations from the revised pro forma OATT and, ultimately, to justify them in the event that they are fairly contested. Otherwise, NRECA contends, the Commission and industry lose the consistency and related advantages the pro forma OATT seeks to provide.

132. Several commenters addressed the deadlines proposed in the NOPR. APPA suggests that the Commission set a 60 or 90-day deadline for those provisions the transmission provider can complete itself and a 120 or 180-day deadline for those provisions and attachments that will require the transmission provider to incorporate regional practices and protocols, such as Attachments C and K. Tacoma proposes 180 days for transmission providers to submit Attachments C and K. PGP recommends that transmission providers be given one year to file Attachment K.

133. EEI and National Grid urge the Commission to align the compliance filing deadlines for ISOs and RTOs and their transmission-owning members in order to eliminate any potential confusion and to enhance coordination within the ISOs and RTOs. To the extent that public utility transmission owners whose transmission facilities are under the control of RTOs and ISOs have filing rights under the RTO or ISO tariffs, EEI asks that such public utility transmission owners be required to submit any necessary tariff filings within 90 days after the effective date of the Final Rule, rather than the currently-proposed 60 days. National Grid suggests that the Commission establish a single deadline for ISOs/RTOs and their transmission-owning members, set at six months from the date of publication of the Final Rule.

134. TDU Systems recommend that the Commission adopt a staggered filing approach for the compliance filings (i.e., have transmission providers come in at different times based on criteria chosen by the Commission, such as alphabetically or by size). TDU Systems argue that this would ensure that transmission customers are not forced to review all of their transmission providers' filings at the same time.

Commission Determination

135. The Commission adopts the two-tiered implementation process proposed in the NOPR, with certain clarifications and modifications, as discussed below. As the Commission proposed in the NOPR, all transmission providers that have not been approved as ISOs or RTOs, and whose transmission facilities are not under the control of an ISO or RTO, are required to submit FPA section 206 compliance filings that contain the revised non-rate terms and conditions set forth in the Final Rule, within 60 days after the publication of the Final Rule in the Federal Register.¹⁰⁵ However, this filing only need contain the revised provisions adopted in the Final Rule, rather than the

¹⁰⁵ The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the pro forma OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.

transmission provider's entire pro forma OATT.¹⁰⁶ After the submission of their FPA section 206 compliance filings, these transmission providers may submit FPA section 205 filings proposing rates for the services provided for in the tariff, as well as non-rate terms and conditions that differ from those set forth in the Final Rule if those provisions are "consistent with or superior to" the pro forma OATT.

136. The Commission recognizes that, since the issuance of Order No. 888, some non-ISO/RTO transmission providers have received approval from the Commission to adopt variations from the non-rate terms and conditions of the pro forma OATT that are consistent with or superior to the Order No. 888 pro forma OATT. Under the compliance procedure adopted above, those variations that are not affected in a substantive manner by the reforms to the pro forma OATT adopted in this Final Rule may remain in place. We disagree with the implementation procedures proposed by APPA, which would require non-ISO/RTO transmission providers with provisions in their OATTs that depart from the pro forma OATT, but which are not substantively affected by the reforms in this NOPR, to make a filing that explains whether and why they would retain or delete these

¹⁰⁶ As explained below, the Commission is not requiring transmission providers to submit in their compliance filing tariff sheets associated with provisions of the pro forma OATT that have not been modified in this proceeding. To the extent, however, a transmission provider desires to refile its entire OATT in order to simplify pagination or other tariff designation issues associated with implementing the modifications required under the Final Rule, it may do so. We note that such a filing is a compliance filing and, therefore, the only deviations in this filing should be the revised provisions in this Final Rule. If a transmission provider wishes to propose different terms and conditions, it must make a separate FPA section 205 filing.

provisions. We see no need to require non-ISO/RTO transmission providers to “rejustify” such provisions if they are not substantively affected by the reforms in this Final Rule, given that the Commission has already found these provisions to be consistent with or superior to terms and conditions set forth in the pro forma OATT that remain unchanged, and the Commission has not otherwise found these provisions to be unjust and unreasonable.

137. In other circumstances, however, non-ISO/RTO transmission providers may have provisions in their existing OATTs that the Commission deemed to be consistent with or superior to terms and conditions of the Order No. 888 pro forma OATT that are being modified by the Final Rule. Such transmission providers must demonstrate that these previously-approved variations continue to be consistent with or superior to the pro forma OATT as modified by the Final Rule. We continue to believe that use of the “consistent with or superior to” standard is appropriate when reviewing variations from the pro forma OATT and reject APPA’s proposal to adopt a higher burden of proof.

138. The two-tiered compliance process adopted above will allow transmission providers with previously-approved variations an opportunity to show that their existing deviations continue to be consistent with or superior to the pro forma OATT as modified in the Final Rule. However, the Commission recognizes that it may cause disruption for some transmission providers that wish to continue to rely on previously-approved variations during the compliance process. The Commission therefore offers an optional

implementation process for non-ISO/RTO transmission providers seeking approval of previously-approved variations.

139. Transmission providers that have not been approved as ISOs or RTOs and whose transmission facilities are not under the control of an ISO or RTO may submit an FPA section 205 filing, within 30 days after the publication of the Final Rule in the Federal Register, seeking a determination that a previously-approved variation from the Order No. 888 pro forma OATT that has been substantively affected by the reforms adopted in this Final Rule continues to be consistent with or superior to the revised pro forma OATT adopted here.¹⁰⁷ Each applicant should request that the proposed tariff provisions be made effective as of the date of the transmission provider's section 206 compliance filing, to be submitted within 60 days after the publication of the Final Rule in the Federal Register (as provided above). As a condition of that request, however, the transmission provider should state that the Commission has 90 days following the date of submission of the filing to act under section 205. In other words, the Commission is offering this optional implementation process to applicants that allow the Commission 90 days to act on the filing. This procedure will streamline the compliance process by allowing existing variations from terms and conditions of the pro forma OATT that have been modified by the Final Rule to remain in effect until further Commission action,

¹⁰⁷ Transmission providers must provide citations to the Commission orders where the variation was accepted by the Commission as consistent with or superior to the pro forma OATT.

while also providing the Commission with adequate time to act on the filings. The subsequent section 206 compliance filing would then contain tariff sheets necessary to implement the remaining modifications required under the Final Rule, i.e., modifications related to tariff provisions that did not implicate previously-approved variations.

140. As the Commission acknowledged in the NOPR, certain non-rate terms and conditions, such as Attachment C (relating to the transmission provider's ATC calculation methodology) and Attachment K (relating to the transmission provider's transmission planning process) may require more than 60 days to prepare. Accordingly, we will require non-ISO/RTO transmission providers to file their Attachment C within 180 days after the publication of the Final Rule in the Federal Register and their - Attachment K (or the transmission providers' equivalent thereof) within 210 days after the publication of the Final Rule in the Federal Register. A summary of the more significant filing requirements established in this Final Rule is provided in Appendix A.¹⁰⁸

141. Other reforms adopted in the Final Rule will involve coordination with the North American Energy Standards Board (NAESB) to establish OASIS functionality or uniform business practices. The Commission requests that NAESB file a status report within 90

¹⁰⁸ For further information related to the Final Rule, such as electronic versions of the pro forma OATT showing tariff changes adopted in the Final Rule in redline/strikeout format, and further information regarding docketing of compliance filings and specific filing instructions, please visit our website at the following location <http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp>.

days of publication of the Final Rule in the Federal Register that contains a work plan for development of such OASIS functionality and business practices. This work plan should indicate, for each reform, what actions are necessary and an estimate of the timeframe for completing those actions. Pending resolution of these issues with NAESB, the Commission requires that each transmission provider develop its own OASIS functionality or business practice necessary to implement each such reform within 90 days of publication of the Final Rule in the Federal Register, unless a different compliance requirement is otherwise specified in this Final Rule. Upon review of this work plan, the Commission will issue an order establishing further compliance deadlines as necessary.

142. We are not persuaded to adopt a staggered compliance filing approach in this proceeding as TDU Systems suggest. However, we will align the compliance filing deadlines for ISOs and RTOs and their transmission-owning members in order to eliminate any potential confusion and to enhance coordination within the ISOs and RTOs. Thus, we will require public utility transmission owners whose transmission facilities are under the control of RTOs and ISOs to make any necessary tariff filings required to comply with the Final Rule within 210 days after the publication of the Final Rule in the Federal Register.

from the tariff modifications required here satisfy the consistent with or superior to standard.

161. As discussed above, however, we will align the compliance filing deadlines for ISOs and RTOs and their transmission-owning members and require public utility transmission owners whose transmission facilities are under the control of RTOs or ISOs to make any necessary tariff filings required to comply with the Final Rule within 210 days after the publication of the Final Rule in the Federal Register. A summary of the more significant filing requirements established in this Final Rule is provided in Appendix A.¹¹⁰

3. Non-Public Utility Transmission Providers/Reciprocity

162. In Order No. 888, the Commission conditioned non-public utilities' use of public utility open access services on an agreement to offer comparable transmission services in return.¹¹¹ The Commission found that, while it did not have the authority to require non-public utilities to make their systems generally available, it did have the ability and the

¹¹⁰ For further information related to the Final Rule, such as electronic versions of the pro forma OATT showing tariff changes adopted in the Final Rule in redline/strikeout format, and further information regarding docketing of compliance filings and specific filing instructions, please visit our website at the following location <http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp>.

¹¹¹ These entities are not FPA public utilities and therefore are not subject to the Commission's jurisdiction under sections 205 and 206 of the FPA.

obligation to ensure that open access transmission is as widely available as possible and that Order No. 888 did not result in a competitive disadvantage to public utilities.

163. Under the reciprocity provision in section 6 of the pro forma OATT, if a public utility seeks transmission service from a non-public utility to which it provides open access transmission service, the non-public utility that owns, controls, or operates transmission facilities must provide comparable transmission service that it is capable of providing on its own system. Under the pro forma OATT, a public utility may refuse to provide open access transmission service to a non-public utility if the non-public utility refuses to reciprocate. A non-public utility may satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary "safe harbor" provision. A non-public utility using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the pro forma OATT. The non-public utility then must offer service under its reciprocity tariff to any public utility whose transmission service the non-public utility seeks to use. Second, the non-public utility may provide service to a public utility under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility may seek a waiver of the reciprocity condition from the public utility.¹¹²

¹¹² See Order No. 888-A at 30,285-86.

164. In EPAAct 2005, Congress authorized, but did not require, the Commission to order non-public utilities (or “unregulated transmitting utilities”) to provide transmission services under a new section 211A in Part II of the FPA. This section states in part that the Commission “may, by rule or order, require an unregulated transmitting utility to provide transmission services” at rates that are comparable to those it charges itself and under terms and conditions (unrelated to rates) that are comparable to those it applies to itself, and that are not unduly discriminatory or preferential. The language does not limit the Commission to ordering transmission services only to the public utility from whom the non-public utility takes transmission services, but rather permits the Commission to order the non-public utility to provide “open access” transmission service, i.e., service to all eligible customers.

165. In the NOPR, the Commission proposed to retain the current reciprocity language in the pro forma OATT, as well as Order No. 888’s three alternative provisions for satisfying the reciprocity condition, i.e.: a non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement, seek a waiver of the OATT reciprocity condition from the public utility, or file a safe harbor tariff with the Commission.¹¹³

¹¹³ For non-public utilities that choose to use the safe harbor tariff, the Commission noted in the NOPR that the existing safe harbor provisions would need to be substantially conforming or superior to the new pro forma OATT. A non-public utility

(continued)

166. The Commission did not propose a generic rule to implement the new FPA section 211A.¹¹⁴ Rather, the Commission proposed to apply its provisions on a case-by-case basis, such as when a public utility seeks service from an unregulated transmitting utility that has not requested service under the public utility's OATT and the reciprocity obligation therefore does not apply. The Commission stated that such a customer may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A. The Commission further proposed to amend its regulations to make clear that an applicant in an FPA section 211A proceeding against a non-public utility that has submitted an acceptable safe harbor tariff has the burden of proof to show why service under the safe harbor tariff is not sufficient and why an FPA section 211A order should be granted. In addition, the Commission stated in the NOPR its expectation that unregulated transmission providers would participate in the proposed open and

that already has a safe harbor tariff would therefore be required to amend its tariff so that its provisions substantially conform or are superior to the new pro forma OATT if it wishes to continue to qualify for safe harbor treatment. As the Commission stated in Order No. 888-A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the pro forma OATT. See Order No. 888-A at 30,289.

¹¹⁴ The Commission noted in the NOPR that LPPC has committed to voluntary compliance with a set of guidelines for the provision of comparable service under FPA section 211A.

transparent regional planning processes and noted that, if there were complaints about such participation, they would also be addressed on a case-by-case basis.

167. The NOPR proposed to retain the existing reciprocity policy as applied to foreign utilities doing business in the United States, which we adopted pursuant to sections 205 and 206 of the FPA. By maintaining the same reciprocity requirement for these foreign utilities as for domestic, non-public utilities, the Commission stated that it would ensure that foreign entities will continue to be treated no less favorably than domestic, non-public utilities.

Comments

168. The majority of the commenters support the Commission's decisions to retain the reciprocity provision and to adopt a case-by-case approach to FPA section 211A.¹¹⁵

These commenters reason that there is no evidence of a general problem of non-public utilities failing to provide transmission service and that, for the most part, non-public utilities already provide transmission on an as-available basis under comparable terms, regardless of whether a tariff is on file with the Commission. In addition, Santa Clara and TANC state that the Commission's proposal apparently respects the nonjurisdictional status of public power.

¹¹⁵ E.g., APPA, Bonneville, LPPC, Newfoundland, NRECA, PGP, Sacramento, Salt River, Santa Clara, Santee Cooper, Seattle, TANC, TAPS, TVA, Tacoma, WAPA, CMUA Reply, East Texas Cooperatives Reply, Lassen Reply, and Public Power Council Reply.

169. LPPC reiterates its prior offer of voluntary compliance with a set of guidelines for the provision of comparable open access service, which it contends will provide a significant degree of standardization for such service. Thus, LPPC believes that generic action under section 211A is not necessary. In addition, LPPC asserts that there is no evidence on record of undue discrimination by a nonjurisdictional entity that would justify the Commission reversing the NOPR decision to act on a case-by-case basis under FPA section 211A.¹¹⁶

170. On the other hand, several commenters urge the Commission to implement FPA section 211A on a generic basis.¹¹⁷ AWEA argues that reciprocity tariffs do not subject the nonpublic utilities to Commission enforcement as would an OATT established under FPA section 211A. AWEA urges the Commission to proceed on a generic basis to ensure that nonjurisdictional utilities comply with the reformed OATT under exactly the same terms and conditions as jurisdictional utilities. On reply, however, APPA argues that the comparability standard does not mean that unregulated transmitting utilities must comply with the reformed OATT under exactly the same terms and conditions as jurisdictional entities.

¹¹⁶ See also Public Power Council Reply and Sacramento Reply.

¹¹⁷ E.g., AWEA, California Commission, Calpine, EEI, MidAmerican, San Diego G&E, and Xcel.

171. In its reply comments, EEI states that, while LPPC's voluntary proposal is a step in the right direction, LPPC's proposal does not go far enough to assure that reciprocal transmission service is provided in a non-discriminatory manner. EEI asserts that LPPC's proposal still gives the individual non-public utility transmission provider the discretion to decide what is or is not comparable and not unduly discriminatory. Moreover, EEI notes, LPPC does not represent the universe of non-public utility transmission providers, rather only 24 of the largest governmentally-owned transmission providers.

172. Some commenters argue that the case-by-case approach proposed in the NOPR does not satisfy the Commission's stated goal of remedying undue discrimination and its intent to provide transparent, consistent and clear rules for use of the nation's transmission grid.¹¹⁸ Calpine contends that the administrative burden of monitoring and administering customer complaints or processing applications that seek to compel unregulated transmitting utilities in different parts of the country to provide comparable service would create a "patchwork of open and closed" unregulated transmitting utilities, just like the patchwork of open and closed jurisdictional transmission systems the Commission sought to eliminate when it issued Order No. 888. Calpine also states that its comments on the NOI in this proceeding provide several examples of the kinds of

¹¹⁸ E.g., Calpine, MidAmerican, and Xcel.

problems it has experienced in seeking transmission service from unregulated transmitting utilities in a variety of regions and across multiple transmission systems.

173. California Commission argues that FPA section 211A gives the Commission the authority to require previously nonjurisdictional entities to file tariffs with the Commission that would be subject to the due process and the “just and reasonable” requirements of the FPA. California Commission urges the Commission to actively explore a set of mandatory actions that the Commission may impose on nonjurisdictional entities and states that, if the Commission is reluctant to do so in this proceeding, it should initiate a new rulemaking to consider such rules. California Commission asserts that there are a number of sound policy reasons for taking generic action to address the mandate of FPA section 211A. First, it argues that Commission action would prevent the balkanization of the grid that can result if a nonjurisdictional transmission owner refuses to participate in an RTO or ISO whose service area surrounds, encompasses, or overlaps it. Second, California Commission argues that Congress has given the Commission explicit authority to require previously nonjurisdictional entities to provide transmission service on a non-preferential and non-discriminatory basis. Finally, California Commission asserts, the Commission would be able to squarely address generic seams issues created by the existence of control areas operated by previously unregulated transmission owners and the ability of such entities to “free ride” on the systems and open access requirements of the jurisdictional entities.

174. In its reply comments, CMUA contests California Commission's assertion that those outside CAISO operations are "free riders." CMUA notes that its members post their excess transmission capacity on westTTrans (an OASIS site serving the Western Interconnection) thus making it available to third parties, and that its members outside the CAISO also pay a host of CAISO fees.¹¹⁹ CMUA states that it does not contest that there are "seams" between organized markets and neighbors, but it asserts that this docket is not the place for this discussion and FPA section 211A is not the remedy. In its reply comments, APPA also urges the Commission to reject California Commission's proposal. APPA argues that section 211A was not intended, nor could the Commission use it, to require nonjurisdictional transmission providers to participate in an RTO and, therefore, California Commission's proposal exceeds the Commission's authority under section 211A.¹²⁰

175. EPSA, in its reply comments, disagrees with commenters who appear to believe that nonjurisdictional transmitting utilities will not have to take any steps to comply with a final order in this rulemaking. EPSA states that its understanding is that the Commission's principle of reciprocity would apply to any changes in the pro forma OATT adopted in the Final Rule. Accordingly, both jurisdictional and nonjurisdictional transmitting utilities that adopted the Order No. 888 pro forma OATT would have to

¹¹⁹ See also APPA Reply.

¹²⁰ See also CMUA Reply and Santa Clara Reply.

make compliance filings. In addition, EPSA argues that nonjurisdictional transmitting utilities that previously received an Order No. 888 waiver or that wish to request such a waiver should have an affirmative duty to file a request for a waiver. In the event that a nonjurisdictional entity wishes to file a bilateral contract, EPSA contends that it should be required to file a "reciprocity" contract pursuant to FPA section 205. If a nonjurisdictional transmitting utility does not adopt a revised pro forma OATT as a "safe harbor," EPSA argues the Commission's standard of review should be whether the nonjurisdictional transmitting utility's alternative tariff is "equal or superior to" a revised pro forma OATT.

176. EPSA, in its reply comments, supports implementing the rate provisions of FPA section 211A in a proceeding separate from this particular proceeding. EPSA states that such a proceeding could take a generic approach, in that nonjurisdictional transmitting utilities could be required to set transmission rates for third-party transmission services that are computed using rate determinants that are comparable to the determinants that the non-public utility uses to calculate transmission rates for its native load.

177. With regard to specific reciprocity obligations, LPPC argues that the Commission should revise section 6 of the pro forma OATT to reflect the comparability standards now contained in FPA section 211A. LPPC states that, with the implementation of FPA section 211A, it is appropriate to revise the pro forma OATT language in order to reflect the unregulated utility's obligation "to provide transmission service comparable to the service the customer provides itself" as the "quid pro quo" for receiving reciprocal

service. LPPC also argues that, with respect to the existing safe harbor option, the Commission should revise its test for evaluating a safe harbor OATT from one which asks whether the proposal is equivalent or superior to the pro forma OATT, to one which asks whether the service provided under the proposed OATT is comparable to the service that the unregulated utility provides itself.

178. EPSA replies that LPPC's suggestion to revise the language of section 6 ironically would require nonjurisdictional transmitting utilities to offer third party customers transmission services that are comparable to network transmission service, which is a higher quality of transmission service than the revised OATT and which is unlikely to be supported by nonjurisdictional transmitting utilities. EPSA states that it believes that FPA section 211A requires a nonjurisdictional transmitting utility to provide transmission service (at its interfaces with jurisdictional public utilities and internal sources) that is comparable to the service it is taking at interfaces or internal sources. EPSA therefore argues that the appropriate standard for determining whether a nonjurisdictional transmitting utility's tariff is comparable is whether the nonjurisdictional utility's tariff is "equal or superior" to the revised pro forma OATT.

179. LPPC also argues that the two categorical exemptions from FPA section 211A articulated in FPA section 211A(c)(3) (based on size and the value of the unregulated system to the integrated grid) should not be exclusive. Rather, LPPC contends that the two exemptions should guide the Commission in considering similar requests for exemption. For example, LPPC argues that relatively small utilities, which nevertheless

exceed an express threshold, should be permitted to demonstrate that their systems are simply too small, and that their facilities are not sufficiently strategic, to call for full inclusion in the FPA section 211A regime. Similarly, LPPC states that, in certain public systems, only some discrete portions of the system would fairly be considered part of the integrated system. In these cases as well, LPPC argues, it would make sense for the Commission to entertain requests for partial waiver.

180. If the Commission does not reconsider its proposal not to act generically under FPA section 211A, EEI contends that there are other actions the Commission should take. In order to facilitate full compliance with the reciprocity obligation, EEI urges the Commission at least to clarify and strengthen the obligations of non-public utility transmission providers under the reciprocity provision,¹²¹ exercise oversight and monitor their compliance with the reciprocity obligation, and require them to provide greater transparency of the transmission services and the terms and conditions of service they offer so that those seeking transmission service under the reciprocity provision are able to determine whether they are complying with their reciprocity obligation.

181. With respect to the reciprocity provision in the pro forma OATT, EEI requests that the Commission update it by including reference to transmission service by ISOs and RTOs. EEI asks that the reciprocity provision be modified to provide that, if an ISO or RTO is the transmission provider, the reciprocity obligation is owed to all members of

¹²¹ Xcel and MidAmerican support EEI's proposal on this issue.

the ISO or RTO. EEI notes, however, that even this action would not require non-public utility transmission providers to provide transmission services to other entities who are eligible customers under the ISO or RTO OATT and who are not transmission providers, such as independent generators. EEI asserts that non-public utility transmission providers may discriminate against certain transmission customers unless the reciprocity obligation is expanded. Sempra Global also asks the Commission to clarify that the right to seek transmission service from an unregulated transmitting utility pursuant to FPA section 211A is available to any entity that qualifies as an eligible customer under the Commission's pro forma OATT.

182. EEI acknowledges that the Commission declined in Order No. 888-A to expand the reciprocity provision beyond the specific transmission provider from which the transmission customer takes service on the ground that requiring "non-public utilities to offer transmission service to entities other than public utility transmission providers increases the chances that they could lose tax-exempt status."¹²² However, EEI states, in 2002, the Department of the Treasury adopted final regulations that in effect provide that providing open access transmission does not constitute private use.¹²³ Therefore, EEI

¹²² Citing Order No. 888-A at 30,287.

¹²³ Treas. Reg. § 1.141-7(g).

argues, this reason for limiting the services provided under the reciprocity obligation is no longer applicable.¹²⁴

183. Moreover, EEI argues, as originally established in Order Nos. 888 and 888-A, the Commission stated that it was “conditioning the use of public utility open access tariffs, by all customers including non-public utilities, on an agreement to offer comparable (not unduly discriminatory services) in return.”¹²⁵ However, EEI states, the reciprocity provision of the pro forma OATT refers to “similar terms and conditions” but does not make clear what they should be “similar” to. EEI argues that the term “similar” does not necessarily encompass the requirement that is part of comparability that the services provided be “not unduly discriminatory” as Order Nos. 888 and 888-A require. EEI proposes that the pro forma OATT be amended to refer to “comparable terms and conditions” rather than “similar” to align it with Order Nos. 888 and 888-A. Finally, EEI also states that the Commission should also reaffirm that the reciprocity obligation is binding on Canadian utilities.

¹²⁴ EEI asserts that the Commission also has the authority to make this change under FPA section 211A, which provides that the Commission may not require a state or municipality to take action under that section that would violate a private utility bond rule. If a non-public utility transmission provider is concerned about the impact on the tax-exempt status of its bonds, EEI suggests that it could seek a waiver from the Commission.

¹²⁵ Citing Order No. 888-A at 30,285.

184. On reply, APPA urges the Commission to reject EEI's proposed expansion of the reciprocity provision. APPA notes that EEI's proposed application of the reforms to all non-public utility transmission providers would potentially include a broader universe of public power entities than those subject to FPA section 211A. Moreover, APPA argues, many of the goals that EEI claims it wishes to accomplish would be accomplished even if the Commission takes no action.

185. In its reply comments, the Canadian Electricity Association urges the Commission to reject EEI's proposal to strengthen the reciprocity obligation so as to require the offering of transmission service to all eligible customers. The Canadian Electricity Association argues that the effect of EEI's proposal would be to enable a generator generating power in Canada to obtain access on a Canadian utility's transmission system, which is not the situation under the current reciprocity requirement. Consequently, the Canadian Electricity Association asserts, EEI's proposal would allow the Commission to fully impose open access requirements in Canada and would violate the principles of comity and undermine Canadian jurisdictional sovereignty.

186. The Canadian Electricity Association also repeats its earlier arguments made in response to the NOI that, to the extent the Commission adopts the comparability standard in FPA section 211A for non-public utilities, the Commission must apply the same changes to Canadian utilities.

187. EEI also urges the Commission to take certain steps to increase transparency and accountability in complying with the reciprocity requirement.¹²⁶ For example, EEI states, the Commission could include on its website a list of all non-public utility transmission providers that have Commission-approved safe harbor reciprocity tariffs. According to EEI, such a list of entities would facilitate use of their transmission systems, provide transparency, and provide recognition to these entities for their voluntary efforts in accomplishing these goals.¹²⁷

188. EEI requests that the Commission also establish minimal transparency requirements for non-public utility transmission providers.¹²⁸ EEI asserts that the

¹²⁶ According to EEI, the new authority granted to the Commission under EPAct 2005 section 1281 (new FPA section 220) (Electricity Market Transparency Rules), which applies to all "market participants," provides another basis for requiring greater transparency under the pro forma OATT by non-public utility transmission providers. EEI argues that the Commission could rely on this new authority to require greater transparency in transmission service provided under the reciprocity obligation.

¹²⁷ EEI notes that, in the NOPR, the Commission referenced voluntary guidelines being developed by members of the LPPC. EEI believes this is a step in the right direction and looks forward to the opportunity to provide input on the proposed guidelines. In EEI's view, however, if any LPPC member wishes to use these guidelines as a safe harbor tariff, it must meet the safe harbor standard that the terms of service must be "substantially conforming or superior to" the revised OATT. The reciprocity obligation requires that the terms and conditions of service be comparable to those that the non-public utility transmission provider applies to itself and not be unduly discriminatory.

¹²⁸ EEI states that this informational filing should include information such as: whether or not they have a reciprocity or other tariff and how it can be obtained, whether they have an OASIS and location URL, whether they have standards of conduct and

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Commission has ample authority under FPA section 211A and under the reciprocity provision of the pro forma tariff to apply this information reporting requirement to those large non-public utility transmission providers that are not exempted by section 211A(c).¹²⁹

189. On reply, several commenters oppose EEI's transparency proposal. Among other things, they argue that EEI's proposal is unnecessary and duplicative of information that is already publicly available – e.g., the non-public utility's website, the Commission's website, or in some instances a regional entity's website (such as the westTTrans OASIS).¹³⁰ APPA further notes that LPPC has proposed that the terms and conditions in non-public utility transmission provider's tariffs would be publicly available on the individual utility's or a regional entity's website. In addition, NRECA asserts that, absent waivers, any non-public utility transmission provider that has adopted a "safe-harbor" tariff has adopted all of the OATT, OASIS, and Standards of Conduct requirements that

where they are posted, whether they have posted business practices, their contact for regional transmission planning, and their ATC methodology

¹²⁹ Section 211A authorizes the Commission to require certain unregulated transmitting utilities to provide transmission services at rates that are comparable to those that the unregulated transmitting utilities charges itself and on terms and conditions (not related 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.

¹³⁰ E.g., APPA Reply, CMUA Reply, LPPC Reply, Lassen Reply, NRECA Reply, Sacramento Reply, and TANC Reply.

apply to public utilities. NRECA and TANC both assert that the Commission does not have similar informational filing requirements for public utilities. Furthermore, TANC argues that it would be a waste of Commission resources to compile a list of all non-public utility transmission providers that have Commission-approved safe harbor tariffs. TANC also argues that to provide such an information filing would be unduly burdensome and a waste of nonjurisdictional utility transmission provider time and limited resources.

Commission Determination

190. The Commission retains the reciprocity language in the Order No. 888 pro forma OATT, but updates it to include references to ISOs and RTOs, as suggested by EEI. We also modify the reciprocity provision to provide that, if an ISO or RTO is the transmission provider, the reciprocity obligation is owed to all members of that ISO or RTO. We concur with EEI's assessment that such modifications will more accurately reflect the current state of the industry. However, we will not adopt EEI's proposal to extend the reciprocity obligation to all eligible customers or LPPC's proposal to revise the pro forma OATT language regarding comparability. We are not persuaded that either proposal is necessary at this time to prevent undue discrimination absent a complaint.

191. We will also retain Order No. 888's three alternative provisions for satisfying the reciprocity condition, i.e.: a non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement; seek a waiver of the OATT reciprocity

condition from the public utility, or file a safe harbor tariff with the Commission. Thus, for non-public utilities that choose to use the safe harbor tariff, its provisions must be substantially conforming or superior to the revised pro forma OATT in this Final Rule. A non-public utility that already has a safe harbor tariff must amend its tariff so that its provisions substantially conform or are superior to the revised pro forma OATT if it wishes to continue to qualify for safe harbor treatment. As the Commission stated in Order No. 888-A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the pro forma OATT.¹³¹ We reiterate that these reciprocity requirements apply equally to all non-public utility transmission providers, including those located in foreign countries.

192. As the Commission proposed in the NOPR, we will not adopt a generic rule to implement the new FPA section 211A. Rather, we will apply its provisions on a case-by-case basis, such as when a public utility seeks service from an unregulated transmitting utility that has not requested service under the public utility's OATT and the reciprocity obligation therefore does not apply. A potential customer may file an application with the Commission seeking an order compelling the unregulated transmitting utility to provide transmission service that meets the standards of FPA section 211A. We adopt

¹³¹ See Order No. 888-A at 30,289.

the NOPR proposal to amend our regulations to make clear that an applicant in an FPA section 211A proceeding against a non-public utility that has submitted an acceptable safe harbor tariff shall have the burden of proof to show why service under the safe harbor tariff is not sufficient and why an FPA section 211A order should be granted.¹³² Further, as we indicate below, we restate our expectation that unregulated transmission providers will participate in the open and transparent regional planning processes ordered below and note that, if there are complaints about such participation or the lack thereof, we will address them on a case-by-case basis.

V. Reforms of the OATT

A. Consistency and Transparency of ATC Calculations

193. In the NOPR, the Commission proposed to take action under FPA section 206 to remedy undue discrimination in the provision of transmission service. The Commission recognized that while Order Nos. 888 and 889 require transmission providers to offer and post any available transfer capability (ATC) on their OASIS, and file the methodology they use to calculate ATC as Attachment C to their OATTs, the industry has not developed a consistent methodology for evaluating ATC nor have transmission providers adequately made their ATC calculation methodology transparent. This inconsistency and lack of transparency creates the potential for undue discrimination in the provision of open access transmission service.

¹³² See revised 18 CFR 35.28(e)(1)(ii).

ISO/RTO footprint and for each LSE or control area footprint within the ISO/RTO. This will not create an undue burden on ISOs and RTOs, since the load data for the entire footprint is an aggregation of load data across the LSEs or control areas in the footprint. We also agree with EEI that the peak load applies to system-wide load, including native load. We direct transmission providers to post load forecasts and actual daily peak load for both system-wide load (including native load) and native load, as this data will be useful to customers and regulators. We deny EEI's request for a guarantee that transmission providers will not be held accountable for producing a reasonable load forecast. While we do not intend to penalize transmission providers for failing to account for unforeseen circumstances, we retain our ability to investigate any allegations of manipulation of load forecasts, as this could be used as a means of inappropriately denying requested transmission service.

417. The Commission is not convinced by the views of some commenters that load data has competitive implications. The Commission notes, as PJM pointed out in its comments, that many RTOs have an established practice of posting significant amounts of load data for participants' use, and this data posting has not raised competitive concerns.

B. Coordinated, Open and Transparent Planning

1. The Need for Reform

418. Order No. 888 set forth certain minimum requirements for transmission system planning. For example, Order No. 888 and the pro forma OATT require that

transmission providers plan and upgrade their transmission systems to provide comparable open access transmission service for their transmission customers. With regard to network service, section 28.2 of the pro forma OATT provides that the transmission provider "will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System." Section 28.2 also provides that the Transmission Provider shall, consistent with Good Utility Practice, "endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers."

419. The pro forma OATT also requires that new facilities be constructed to meet the service requests of long-term firm point-to-point customers. Section 13.5 of the pro forma OATT requires the transmission provider to consider redispatch of the system to relieve any constraints that are inhibiting a transmission customer's point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system. This expansion obligation on the part of the transmission provider for point-to-point service is found in section 15.4 of the pro forma OATT, which provides that, when a transmission provider cannot accommodate a request for point-to-point transmission because of insufficient capability on its system, it will "use due diligence to expand or modify its Transmission System to provide the requested

Firm Transmission Service.” Section 15.4 goes on to provide that “the Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities.” The transmission provider’s obligation to upgrade or expand its system to provide point-to-point service as detailed in section 15.4 is contingent on the transmission customer agreeing to compensate the transmission provider for such costs pursuant to the terms of section 27 (providing for cost responsibility for upgrades and/or redispatch “to the extent consistent with Commission policy”).

420. In Order No. 888-A, the Commission encouraged utilities to engage in joint planning with other utilities and customers and to allow affected customers to participate in facilities studies to the extent practicable. The Commission also encouraged regional planning so that the needs of all participants are represented in the planning process.²²⁵ Order No. 888-A did not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region.²²⁶ The only section of the existing pro forma OATT that directly speaks to joint planning is section 30.9, which

²²⁵ See Order No. 888-A at 30,311.

²²⁶ See id.

provides that a network customer must receive credit when facilities constructed by the customer are jointly planned and installed in coordination with the transmission provider.²²⁷

421. As the Commission stated in the NOPR, the Nation has witnessed a decline in transmission investment relative to load growth in the ten years since Order No. 888 was issued. Transmission capacity per MW of peak demand has declined in every NERC region. Transmission constraints plague most regions of the country, as reflected in the limited amounts of ATC posted in many regions, increased frequency of denied transmission requests, increasingly common transmission service interruptions or curtailments and rising congestion costs in organized markets.²²⁸

²²⁷ Pro forma OATT section 21.2, "Coordination of Third-Party System Additions," provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, but imposes no obligation on transmission providers.

²²⁸ The number of TLRs has increased significantly since NERC started reporting annual statistics. The total number of TLRs each year has grown from under 500 in 1998 and 1999 to around 2000 over the last four years from 2002 to 2006. The number of TLR actions at the highest levels, requiring curtailment of firm transmission flows, has also grown, from under 10 before 2001 to 70 in 2006, averaging 55 per year from 2003 to 2006. Source: NERC Website, ftp://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm In addition, congestion costs continue to be a major issue in RTO markets. For example, congestion costs in PJM were \$2.09 billion in calendar year 2005, which was a 179 percent increase over 2004. Although this increase resulted primarily from increases in PJM annual billings, the congestion costs in both years were approximately 9 percent of total PJM billings in both years and have ranged from 6 percent to 10 percent of total billings since 2000. Source: 2005 PJM State of the Markets Report, April 2006.

422. We do not believe that the existing pro forma OATT is sufficient in an era of increasing transmission congestion and the need for significant new transmission investment. We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

423. As the Commission explained in Order No. 888, "[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves."²²⁹ The court agreed on review of Order No. 888, noting in TAPS v. FERC that "[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their

²²⁹ Order No. 888 at 31,682.

own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers.”²³⁰ The Supreme Court in New York v. FERC similarly explained that “public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities’ control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors’ power on terms and conditions less favorable than those they apply to their own transmissions.”²³¹

424. The existing pro forma OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider’s planning obligation. Although the pro forma OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions.²³² Rather, transmission

²³⁰ 225 F.3d at 684.

²³¹ 535 U.S. at 8-9 (citation and footnotes omitted).

²³² As discussed in more detail in the NOPR, the need for reform was recognized by the Consumer Energy Council of America (CECA), a public interest energy policy organization with a 30-year history of bringing stakeholders together to find solutions to contentious energy policy issues. CECA launched its Transmission Infrastructure Forum in early 2004, which published its conclusions in January 2005 in a final report titled “Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability” (CECA Report).

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providers may develop transmission plans with limited or no input from customers or other stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers.

425. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning.²³³ The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service and, therefore, an obligation to remedy these transmission

Among other things, the CECA Report concludes that regional transmission planning with consumer input early in the process is needed to ensure the development of a robust transmission system capable of meeting consumer needs reliably and at reasonable cost over time. The CECA Report stresses that regional transmission planning must address inter-regional coordination, the need for both reliability and economic upgrades to the system, and critical infrastructure to support national security and environmental concerns. See NOPR at P 207.

²³³ In our discussion of enforcement issues at section V.E of this Final Rule, we note specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations involving transactions with affiliates. While these specific situations may not directly relate to discrimination in planning, they nevertheless document the continuing incentive of transmission providers to favor themselves and their affiliates in the provision of transmission service.

planning deficiencies. As we explain above, our authority to remedy undue discrimination is broad.²³⁴ In addition, new section 217 of the FPA requires the Commission to exercise its jurisdiction in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of LSEs. A more transparent and coordinated regional planning process will further these priorities, as well as support the DOE's responsibilities under EPCA 2005 section 1221 to study transmission congestion and issue reports designating National Interest Electric Transmission Corridors and the Commission's responsibilities under EPCA 2005 section 1223.

NOPR Proposal

426. In order to provide for more comparable open access transmission service, limit the potential for undue discrimination and anticompetitive conduct, and satisfy its statutory responsibilities under section 217 of the FPA, the Commission proposed to amend the pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. Each public utility transmission provider would be required to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following eight planning principles: coordination, openness, transparency, information exchange,

²³⁴ See Order No. 888 at 31,669 (noting that the FPA "fairly bristles" with concern for undue discrimination (citing AGD, 824 F.2d at 998)).

comparability, dispute resolution, regional participation, and congestion studies. In the alternative, transmission providers could make a compliance filing in this proceeding describing their existing coordinated and regional planning processes and showing that they are consistent with or superior to that required in the Final Rule.

427. The Commission stated that it expected non-public utility transmission providers to participate in the proposed planning processes, given that effective regional planning cannot occur without the participation of all transmission providers, owners, and customers. Although the Commission encouraged the use of an independent third party to oversee or coordinate the planning process, the NOPR did not propose to require it. The Commission also strongly encouraged the participation of state commissions and other state agencies in planning activities.

428. The Commission sought comment on several aspects of the NOPR proposal. First, the Commission inquired as to the level of flexibility each transmission provider should be given in implementing any principles adopted. Second, the Commission sought comment, by way of example, on transmission planning processes that comply with the NOPR reforms in principle. Third, the Commission sought comment on whether there are other principles or requirements that should be adopted to support the construction of needed new infrastructure and otherwise ensure that all market participants are treated on a comparable basis. Specifically, the Commission inquired: (a) whether there should be a principle or guideline to govern the recovery and allocation of costs associated with funding the regional planning requirement; (b) whether there should be a requirement

that, at least for large new transmission projects, there be an open season to allow market participants to participate in joint ownership of these projects; (c) whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion; and, (d) whether public utilities should be required to develop cost allocation principles to address the sharing of the costs of new transmission projects and, given that such projects can take years to construct, whether the planning process should be required to look out at least as far as the longest time it would take to build such an upgrade in the region in question. Finally, the Commission sought comment on the level of detail to be required in transmission providers' OATTs.

Comments

429. Most commenters support the development of coordinated, open, and transparent planning. While differing on how they should be implemented, commenters express broad support for the eight planning principles,²³⁵ though all RTOs and ISOs and many investor-owned utilities believe that their planning processes already comply with the proposals in the NOPR. ISO/RTO Council, as well as individual RTOs and ISOs, advance the position that RTOs and ISOs already meet the planning requirements in the NOPR, that there has been no credible case made for reopening their already approved

²³⁵ The one exception is the congestion studies requirement, which is generally opposed by transmission providers and supported by customers.

planning processes, and that RTOs and ISOs should be exempt from complying with the NOPR's planning principles.

430. Some transmission providers agree that RTOs already meet the principles, and others argue against commenters who maintain that RTOs "rubber stamp" transmission provider plans.²³⁶ For example, MISO asserts that it conducts an open planning process and does not "rubber stamp" projects. Duke concurs with MISO, stating that there are abundant opportunities for participation in the MISO planning process. Xcel also replies in support of the MISO process.

431. Several transmission customers, however, argue that current RTO processes are insufficient because, among other things, they merely accept the transmission owners' plans and only provide for after-the-fact input, thus failing to satisfy the planning principles proposed in the NOPR.²³⁷ Old Dominion also asserts that RTOs generally approve transmission owner identified upgrades, which give them the advantage of having their own parochial plans incorporated into the regional plan without any separate evaluation or complete stakeholder input. TAPS asserts that open planning should apply both to the RTO and the underlying transmission owners' planning efforts. In its reply, WPS opposes MISO's proposal to be exempt from the NOPR's planning requirements,

²³⁶ E.g., Duke, Exelon, and Xcel.

²³⁷ E.g., Indicated Parties Reply, Old Dominion, NRECA, and TAPS.

arguing that the MISO process is not open and only aggregates the plans of the transmission providers.

432. EEI takes issue with broad statements in the NOPR that assert that transmission providers have a disincentive to remedy transmission congestion and to plan their transmission systems on a comparable basis. Other individual investor-owned utilities also assert that the record does not support the NOPR's claims that a mandatory coordinated, open, and transparent planning process is necessary to remedy undue discrimination.²³⁸ Many others, however, believe the NOPR correctly diagnoses the problem of discrimination.²³⁹

433. Most commenters do not question the Commission's jurisdiction to address the transmission planning process generally. Southern, however, argues that the Commission has no general authority in this area and that section 217 of the FPA does not grant the Commission any additional jurisdiction to impose a regional planning requirement.²⁴⁰ FMPA counters that the Commission has FPA authority to cure undue discrimination and to ensure "just and reasonable" transmission rates and terms by adopting transmission

²³⁸ See, e.g., Duke and Southern.

²³⁹ See, e.g., APPA and EPSA. However, NRG and Reliant believe that the planning process outside of RTOs is fundamentally flawed and cannot be remedied by the NOPR's planning proposal.

²⁴⁰ Progress Energy also claims that the Commission does not have any jurisdiction to mandate regional planning.

planning criteria.²⁴¹ In their replies, APPA and TAPS agree with the Commission that FPA section 217(b)(4) can be cited as legal support for transmission planning. In its reply, NRECA stresses that the transmission planning process must focus, consistent with FPA section 217(b)(4), on the reasonable long-term needs of LSEs, not all users of the system as argued by EPSA and NRG. Santee Cooper urges the Commission to be mindful of the limits of its jurisdiction in establishing study requirements that may delve into generation resource adequacy or issues related to the mix of generation. Other commenters urge the Commission not to impinge on state jurisdiction.²⁴² In its reply, LPPC emphasizes that the Commission's expectation that public power entities will participate is sufficient and asserts that there is no reason to take further action that might test the limits of jurisdiction under FPA section 211A.²⁴³

434. WIRES endorses several planning objectives it believes to be critical to successful planning. These objectives include open and transparent planning procedures, a long-term planning horizon, broad-based inclusion of reliability, economic, efficiency and

²⁴¹ See also TAPS Reply.

²⁴² See, e.g., Nevada Companies, New Mexico Attorney General, North Carolina Commission Reply, and Southern.

²⁴³ Other jurisdictional arguments primarily relate to the question of joint ownership, in which some commenters argue that the Commission lacks jurisdiction to mandate joint ownership arrangements. See, e.g., Duke, EEI, National Grid, Northeast Utilities, PSEG, and Southern. FMPPA and others, however, argue that the Commission does have the authority to order joint ownership. Joint ownership will be discussed more fully below.

environmental considerations in planning, clear conditions under which a transmission owner will commit to build planned facilities, and provision for fair and efficient allocation of the costs of planned facilities. WIRES also emphasizes the importance of considering non-transmission alternatives, arguing that an appropriate grid plan must be based on an integrated view of all alternatives, including demand response and distributed generation.

Commission Determination

435. In order to limit the opportunities for undue discrimination described above and in the NOPR, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. We disagree with commenters arguing either that we lack jurisdiction to require coordinated transmission planning or that we have not established a basis for such a requirement. The Commission has broad authority to remedy undue discrimination by ensuring that transmission providers plan for the needs of their customers on a comparable basis.²⁴⁴ That fundamental requirement was adopted in Order No. 888 and the reforms adopted herein should ensure that it will be implemented properly. Further, we explained in detail above

²⁴⁴ See AGD, 824 F.2d at 1008 (Commission has broad discretion to promulgate generic rules to eliminate undue discrimination without “conduct[ing] experiments in order to rely on the prediction that an unsupported stone will fall”).

why undue discrimination remains a concern in the planning area and why the existing OATT is insufficient to address that concern.

436. New section 217 of the FPA further supports reform in this area, as it reflects Congress' intent that the Commission utilize its powers to facilitate the planning and expansion of the transmission system.²⁴⁵ Through EPA 2005 sec. 1223, Congress also directed the Commission to encourage the deployment of advanced transmission technologies in infrastructure improvements, including among others optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells, and microturbines), and enhanced power device monitoring.

437. Accordingly, each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule.²⁴⁶ In the alternative, a transmission provider (including an RTO or an ISO, as

²⁴⁵ FPA section 217(b)(4) provides that "[t]he Commission shall exercise the authority of the Commission under [the FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long term basis for long term power supply arrangements made, or planned, to meet such needs."

²⁴⁶ The pro forma OATT, as modified by this Final Rule, reflects the proposed planning requirement in sections 15.4, 16.1, 17.2(x), 28.2, 29.2, 31.6. The planning process itself will be included as Attachment K to the pro forma OATT. We understand
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discussed below), may make a compliance filing in this proceeding describing its existing coordinated and regional planning process, including the appropriate language in its tariff, and show that this existing process is consistent with or superior to the requirements in this Final Rule. Under either of these approaches, the process must be documented as an attachment to the transmission provider's OATT.

438. At the outset, we note that the planning obligations imposed in this Final Rule do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Furthermore, except for the discussion below of cost allocation for transmission investments under Principle 9, the planning obligations included in this Final Rule do not address whether or how investments identified in a transmission plan should be compensated. Through the principles described below, we establish a process through which transmission providers must coordinate with customers, neighboring transmission providers, affected state authorities, and other stakeholders in order to ensure that transmission plans are not developed in an unduly discriminatory manner.

439. As for the application of the Final Rule's coordinated planning requirement to RTOs and ISOs, which already have a Commission-approved transmission planning process on file with us, we note that the intent of our reform in this Final Rule is not to

that some transmission providers may already have attachments to their OATTs labeled with the letter "K," in which case transmission providers are free to label their planning process OATT attachment with the next available letter.

reopen prior approvals, but rather to ensure that the transmission planning process utilized by each RTO and ISO is consistent with or superior to the planning process adopted here. When the Commission approved the existing RTO and ISO transmission planning processes, they were found to be consistent with or superior to the existing pro forma OATT. Because the pro forma OATT is being reformed by this Final Rule, it is necessary for each RTO and ISO to now either reform its process or show that its planning process is consistent with or superior to the pro forma OATT, as modified by the Final Rule.

440. We also make clear that transmission owning members of ISOs and RTOs must participate in the planning processes adopted in this Final Rule. In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. This is important because, in many cases, RTO planning processes may focus principally on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners. These local planning issues, however, may be critically important to transmission customers, such as those embedded within the service areas of individual transmission owners. Consequently, the intent of the Final Rule will not be realized if only the regional planning process conducted by the RTOs and ISOs is shown to be consistent with or superior to the Final Rule. To ensure full compliance, individual transmission owners must, to the extent that they perform transmission planning within an RTO or ISO, comply with the Final Rule as well.

Without such a requirement, the more regional RTO or ISO planning process will not comply with the requirements of the Final Rule to the extent they incorporate and rely on information prepared by underlying transmission owners that, in turn, have not complied with the Final Rule. Accordingly, as part of their compliance filings in this proceeding, RTOs and ISOs must indicate how all participating transmission owners within their footprint will comply with the planning requirements of this Final Rule. While we leave the mechanics of such compliance to each RTO and ISO, we emphasize that the RTO's or ISO's planning processes will be insufficient if its underlying transmission owners are not also obligated to engage in transmission planning that complies with Final Rule.²⁴⁷

441. The Commission also expects all non-public utility transmission providers to participate in the planning processes required by this Final Rule. A coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. We are encouraged, based on the representations of LPPC and others, that non-public utility transmission providers will fully participate in such processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA

²⁴⁷ We understand that there are some transmission owners in RTOs or ISOs that continue to have OATTs on file under which they provide service over certain transmission facilities that they did not turn over to the operational control of the RTO or ISO. Like any other transmission provider, those entities must submit a compliance filing to their OATTs that satisfies all requirements of this Final Rule, including the inclusion of an attachment governing their own planning procedures. As we explain elsewhere, the compliance filing deadline for transmission owning participants in RTOs and ISOs shall be the same as the RTO and ISO deadline, *i.e.*, 210 days after publication of the Final Rule in the Federal Register.

section 211A, which gives us authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis.²⁴⁸ If we find on the appropriate record, however, that non-public utility transmission providers are not participating in the planning processes required by this Final Rule, the Commission may exercise its authority under section 211A on a case-by-case basis. Further, we note 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.

442. In sum, each OATT planning process attachment must incorporate the transmission planning principles and concepts in this Final Rule and must be filed with the Commission within 210 days after the publication of the Final Rule in the Federal Register. Alternatively, RTOs, ISOs, and other transmission providers that currently have planning processes they believe comply with the Final Rule may make a filing with the Commission documenting those processes in an OATT attachment and explaining

²⁴⁸ FPA section 211A(b) provides, in pertinent part, that “the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.” The non-public utility transmission providers referred to in this Final Rule include unregulated transmitting utilities that are subject to FPA section 211A.

how their planning processes are consistent with or superior to the planning process adopted here. Such filings must also be submitted within 210 days after the publication of the Final Rule in the Federal Register.

443. In order to assist transmission providers in complying with the Final Rule, and ensure that the planning procedures are developed with customer and stakeholder participation, the Commission will convene staff technical conferences in several broad regions around the country to discuss regional implementation and other compliance issues in advance of the compliance date. We extend an invitation to state regulatory commissions to participate in these technical conferences with our staff in order to ensure that state concerns are fully addressed. The Commission will endeavor to hold the technical conferences 90 to 120 days after the publication of the Final Rule in the Federal Register. To facilitate these conferences, each transmission provider should, within 75 days after the publication of the Final Rule in the Federal Register, post a "strawman" proposal for compliance with each of the planning principles adopted in the Final Rule, including a specification of the broader region in which it will conduct coordinated regional planning. This strawman may be posted on the transmission provider's OASIS, or its website if it does not have its own OASIS (e.g., in the case of a transmission owning member of an RTO or ISO that does not have its own OATT). We strongly urge transmission providers to consult with their stakeholders in the development of this strawman.

2. Planning Principles

444. We set forth below the planning principles that must be satisfied for a transmission provider's planning process to be considered compliant with the Final Rule. The NOPR identified eight such principles, but based on the comments received the Commission will require compliance with nine – the original eight plus a cost allocation principle, as described further below.

a. Coordination

445. In the NOPR, the Commission proposed that transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. We sought comment on specific requirements for this coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features deemed important by commenters.

Comments

446. Commenters express universal support for the general concept of coordination, but differ on how specific the requirement should be. Several commenters argue that the requirement that transmission providers “must meet” with customers and utilities is unrealistic.²⁴⁹ EEI requests that the Commission clarify that transmission providers will

²⁴⁹ E.g., Allegheny, Duke, EEI, International Transmission, MidAmerican, NorthWestern, and SCE.

be responsible for coordinating with customers and holding meetings, but that the requirement to meet should be limited to making reasonable efforts to meet with all customers. NRECA asks on reply that the Commission make clear that the lack of full participation by some nonjurisdictional utilities that take network service under the OATT should not excuse the transmission provider's obligation to engage in transmission planning. NRECA states that inclusion in the planning process must be an opportunity for LSEs, not an obligation.

447. Other commenters express a more general concern that the Commission not be prescriptive with respect to meeting requirements.²⁵⁰ For example, most commenters generally believe the Commission should not prescribe rigid rules regarding the number of meetings that must be held each year. Xcel, however, suggests that a minimum of three meetings a year would be appropriate. Progress notes that coordination in North Carolina already occurs as a result of regular meetings throughout the year. Nevada Companies believe that meetings should be dependent on need and should not be programmatically established. TDU Systems recommend at least monthly meetings, but stress that meetings should be as frequent as is required to specify and perform the studies forming the basis for the plan. NCPA believes that the minimum requirements

²⁵⁰ E.g., Allegheny, APPA, Bonneville, California Commission, Duke, Entergy, Imperial, International Transmission, MidAmerican, NCEMC, NC Transmission Planning Participants Reply, NorthWestern, NRECA, Pinnacle, Progress Energy, CREPC, Santee Cooper, SCE, TVA, and WAPA.

are not as important as how they can be monitored or enforced to ensure that true participation indeed occurs.

448. Seattle suggests 30 days notice for meetings and that information regarding meetings be posted at least one week in advance. Entergy finds a notice requirement reasonable, and other utilities suggest a 30-day requirement would be appropriate.²⁵¹

Seattle also suggests e-mail notification and Salt River supports internet posting. With respect to details beyond frequency and notice, Entergy cautions the Commission against being too prescriptive.

449. On meeting scope, several commenters request that the Commission make clear that the purpose of the meeting is to focus on transmission issues and not provide a broad forum for other issues.²⁵² Sacramento believes that meetings should be limited to sub-regional or regional transmission planning and not include planning to meet local transmission needs.

450. Other commenters stress that joint planning requires more than just meeting with customers and that all LSEs need to be integrated into the planning process so that they are actively developing transmission plans alongside transmission providers from the inception.²⁵³ This concept of collaborative planning is a running theme in the comments

²⁵¹ E.g., Nevada Companies and North Western.

²⁵² E.g., Entergy, Progress Energy, SCE, and Southern.

²⁵³ E.g., NRECA, Seminole Reply, TAPS, and TDU Systems.

provided by several public power entities, such as NRECA, TAPS, and TDU Systems. TDU Systems argue that comparability requires that LSEs have equal weight in decision-making rather than provide de facto veto authority to transmission providers. NRECA argues in its reply that collaborative planning is required by FPA section 217(b)(4). These commenters assert that LSEs must be able to participate in the development of planning models, including the assumptions and criteria that go into these models, and in the development of the base case and change case for study purposes, particularly as to the identification and projection of loads and resources.²⁵⁴ Progress and Southern, however, argue in replies that giving customers equal weight in decision-making crosses the line from planning to control by third parties, and Southern believes this would be opposed by state regulators.

Commission Determination

451. The Commission adopts the coordination principle proposed in the NOPR. Commenters overwhelmingly desire flexibility as to the coordination principle, and as such, we will not prescribe the requirements for coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice

²⁵⁴ This collaborative approach is also generally supported by East Texas Cooperatives, FMPPA, NCEMC, NCPA, and Old Dominion. NCEMC believes that the key to ensuring true collaboration is a voting structure, like that adopted in the North Carolina Transmission Planning Collaborative, which gives all load-serving entities an equal say in planning decisions. APPA also believes that giving customers a say in the outcome (e.g., through voting) is critical.

requirements, the format, and any other features. We will allow transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders.

452. We emphasize that the purpose of the coordination requirement is to eliminate the potential for undue discrimination in planning by opening appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected state authorities, customers, and other stakeholders. Rigid and formal meeting procedures may be one way to accomplish this goal, but there may be other ways as well. For example, a transmission provider could meet this requirement by facilitating the formation of a permanent planning committee made up of itself, its neighboring transmission providers, affected state authorities, customers, and other stakeholders. Such a planning committee could develop its own means of communication, which may or may not emphasize formal meeting procedures. We are more concerned with the substance of coordination than its form.

453. In response to the concerns of some commenters, we clarify that transmission providers are not required to meet with customers and other stakeholders that choose not to meet. Transmission providers cannot force others to meet with them. Transmission providers are, however, required to craft a process that allows for a reasonable and meaningful opportunity to meet or otherwise interact meaningfully. We also clarify that the coordination requirements imposed in this Final Rule are intended to address

transmission planning issues, and are not intended to provide a forum for ancillary issues, such as specific siting concerns, which are better addressed elsewhere. As for NRECA's concern that transmission providers must plan for their nonjurisdictional network customers even if they decline to fully participate in the planning process, a transmission provider cannot be expected to effectively plan for a customer if that customer declines to engage in the planning process. Therefore, we encourage NRECA and non-public utilities to participate fully in the planning process.

454. In response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarify that transmission planning is the tariff obligation of each transmission provider, and the pro forma OATT planning process adopted in this Final Rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers. With this said, we fully intend that the planning process adopted herein provide for the timely and meaningful input and participation of customers into the development of transmission plans. This means that customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.

b. Openness

455. In the NOPR, the Commission proposed that transmission planning meetings must be open to all affected parties (including all transmission and interconnection customers and state authorities). The Commission also sought comment on whether there are any circumstances under which participation should be limited, for example, to address confidentiality concerns.

Comments

456. Commenters generally agree on the need to meet with all affected parties, as well as the need to limit some meetings for security or confidentiality reasons. Certain commenters urge the Commission to make clear that openness does not extend to a requirement to meet with the general public and that the meetings are for "industry and governmental representatives" only.²⁵⁵ For example, Southern agrees that eligible transmission customers and state commissions should be allowed to participate in the meetings, but states that these meetings should not be open to the general public to help ensure that the focus is on core transmission planning and not be diverted to other issues.

457. Transmission providers generally note that some meetings will need to be limited for CEII concerns or for discussion of commercially-sensitive information.²⁵⁶ Progress

²⁵⁵ E.g., APPA, EEI, Salt River, and Southern.

²⁵⁶ Other commenters also recognize the need to maintain confidentiality for CEII and commercially-sensitive information. E.g., Arkansas Commission, AWEA, California Commission, NCPA, NRECA, CREPC, Seattle, TDU Systems, and WAPA.

Energy states the Commission should be flexible regarding the composition of meetings and openness, noting that in North Carolina meetings involving CEI are limited to transmission personnel and non-marketing personnel of participating LSEs, while other meetings in the North Carolina process are open to the public. In their reply, NC Transmission Planning Participants note that they have been able to negotiate confidentiality protocols agreeable to each of them. Duke believes that restrictions on open meetings need to be in place when sensitive commercial information is being discussed, so that personnel engaged in the merchant function do not gain access to sensitive information about their competitors. Indianapolis Power recommends the Commission keep existing restrictions on access to planning meetings in place to preserve current protections on security and competitive information. TVA states that it is particularly concerned with maintaining confidentiality and asks the Commission to defer to NERC and its Regional Entities, which TVA says are developing procedures for planning.

458. Commenters also raise issues regarding the application of the Commission's Standards of Conduct to those that participate in planning meetings.²⁵⁷ EEI, for example, believes that if information is disclosed during a planning meeting and is not

²⁵⁷ Commenters raise issues with regard to the application of the Commission's Standards of Conduct to planning participants in their comments addressing some of the other principles as well, which will be discussed below, as well as addressed in the pending rulemaking in Docket No. RM07-1-000. See Standards of Conduct NOPR.

simultaneously made public, then all planning participants – including nonjurisdictional entities— should be subject to the Commission’s Standards of Conduct. APPA understands the need to ensure that non-public information obtained during planning meetings is not utilized to gain an unfair advantage in the power market; however, it believes that other means short of the application of the Standards of Conduct would suffice, such as requiring simultaneous disclosure of information as a “safe harbor” or the use of confidentiality agreements.²⁵⁸

459. NRECA and TDU Systems argue that meetings should be open and, joined by APPA, suggest that confidentiality issues can be managed with confidentiality agreements and other arrangements (such as password protected access to information). TAPS suggests that access to data be limited to transmission dependent utility employees not involved in marketing or to an outside consultant. California Commission stresses that any advisory subcommittees must also be open to all stakeholders.

Commission Determination

460. The Commission adopts the NOPR’s proposal and will require that transmission planning meetings be open to all affected parties including, but not limited to, all transmission and interconnection customers, state commissions and other stakeholders. We recognize that it may be appropriate in certain circumstances, such as a particular meeting of a subregional group, to limit participation to a relevant subset of these entities.

²⁵⁸ See also East Texas Cooperatives Reply and NRECA Reply.

We emphasize, however, that the overall development of the transmission plan and the planning process must remain open. We agree with the concerns of some commenters that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities. Accordingly, we will require that transmission providers, in consultation with affected parties, develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns. Lastly, concerns surrounding the application of the Commission's Standards of Conduct to planning participants, and whether and how these standards should affect access to and use of information obtained in the planning process, will be discussed below.

c. Transparency

461. In the NOPR, the Commission proposed that transmission providers be required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. The Commission also sought comment on whether the information provided in FERC Form 715 (Form 715) is adequate and, if not, what additional detail should be provided. In addition, the Commission sought comment on the format for disclosure, including protections to address confidentiality concerns.

Comments

462. Transmission providers generally agree that they should provide the basic criteria, assumptions, and data for planning, but argue that non-public utility transmission

providers should also be required to provide comparable information.²⁵⁹ In general, EEI believes that information provided during the planning process should be treated as confidential and not disclosed to the general public.

463. Public power entities and other commenters support transparency and also are sensitive to confidentiality concerns.²⁶⁰ NCPA believes that the failure of CAISO to release planning data is one of the biggest failings of CAISO planning process. Without access to criteria, assumptions, and data inputs, NCPA argues that customers cannot duplicate planning results, nor can they independently determine whether the assumptions are correct, whether the model is producing the right results, whether those results are being fairly applied in the choice of projects to be undertaken, or assess the impacts on their own customers. APPA suggests that transmission providers be required to reduce to writing the methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. CREPC points out that transparency is necessary if state regulatory processes are to give deference to planning results. Sacramento asserts that it may be reasonable to allow customers and stakeholders access to the planning

²⁵⁹ E.g., CAISO, EEI, and SCE.

²⁶⁰ E.g., APPA, California Commission, NCPA, CREPC, Salt River, and WAPA. Old Dominion, however, does not believe that any of the data required to be disclosed is commercially-sensitive; however, it does recognize that it may be CEII, in which case it claims security can be maintained via a secure OASIS site.

model or at least allow access to a comprehensive description of the model and methodology, in order to allow others to closely replicate the planning analysis.

Sacramento is joined by Imperial in referencing WECC's on-going effort to increase planning transparency.

464. NRECA and TDU Systems, however, do not believe that a specific disclosure principle would be necessary if LSEs were truly integrated into the planning process. In other words, they argue that if the process is truly open, then LSEs, as participants in the development of the joint plan, should already have access to the inputs and assumptions underlying the plans and, in fact, should have helped develop them.

465. EEI believes that Standards of Conduct requirements should be placed on all participants in the planning process whenever disclosure of commercially-sensitive information is needed for planning. East Texas Cooperatives argues that the Standards of Conduct should not be generically applied to public power and that such issues should be managed with confidentiality agreements and case-by-case protective orders. In its reply, NRECA also asserts that, while it is necessary to protect competitively-sensitive information, there is no basis for requiring nonjurisdictional entities to comply with the formal separation of functions requirements simply because they have received information in the planning process, as this is inconsistent with the cooperative utility business model. Rather, NRECA believes commercially-sensitive information can be handled in other established ways. APPA also suggests that Standards of Conduct issues

can be managed by providing for certain “safe harbors” for participation, such as simultaneous disclosure of information or the use of an independent facilitator.²⁶¹

466. Commenters express a range of views on the information found in Form 715.

MidAmerican believes Form 715 to be more than adequate and recommends shortening or eliminating it. Other investor-owned utilities find Form 715 to be generally sufficient.²⁶² Others believe the information in Form 715, as currently supplemented by other information in the planning process, is adequate.²⁶³ Duke and WAPA contend that Form 715 does not contain sufficient information for transmission planning, but believe that disclosure of further details should be left to stakeholders. According to NorthWestern, Form 715 contains the basic data, but may not always provide the needed information.

467. ISO/RTO Council believes that Form 715 data are generally inadequate for planning studies, but urges the Commission not to attempt to develop “standardized forms” for these and other types of data. CAISO also cautions against adopting a

²⁶¹ NARUC asks the Commission to re-examine the need for its Standards of Conduct rules concerning communications between resource and transmission planners in light of the mitigation provided by the open planning processes proposed in the NOPR.

²⁶² E.g., Indianapolis Power, Southern, and Xcel.

²⁶³ E.g., Allegheny (with data from PJM) and Nevada Companies (with data from WECC).

standardized form for the collection of necessary information, because standardized forms do not necessarily provide the information needed by individual providers.

468. A number of other commenters believe that Form 715 information is insufficient.²⁶⁴ APPA and TAPS point out that Form 715 does not include all the information needed to perform a load flow study, including information on economic dispatch and interchange, and also that Form 715 information is out of date when filed. Seattle notes that typical sub-regional planning processes go into significantly greater detail than Form 715 and argues that Form 715 is primarily a reliability-focused report that seldom delves into economic analysis of congestion and transmission options that mitigate congestion.

469. Several commenters contend that transparency in the planning process is of particular interest to demand resources. New Jersey Board suggests that each transmission provider's planning process analyze whether demand resources or other solutions could be considered as an alternative or a component of new transmission lines or upgrades. New Jersey Board states that this analysis should include both supply-side and demand-side measures such as load management, new building codes and energy efficiency standards, the use of distributive renewable energy systems, and renewable

²⁶⁴ E.g., APPA, California Commission, NCPA, CREPC, Seattle, TAPS, and TDU Systems. California Commission and CREPC also point out that the load forecast information presently used in planning in the Western Interconnection is likewise insufficient.

portfolio standards. Ohio Power Siting Board argues that an open, transparent, and inclusive regional planning process should include distributed generation, demand response, and new technology as part of the mix of available options for incremental or interim congestion relief until longer term solutions can be developed and constructed. Fayetteville notes its general support for a SEARUC joint planning proposal, which includes a principle that would require the integration of demand response in planning. WIRES likewise argues that an appropriate grid plan should be based on an integrated view of all alternatives, including demand response and distributed generation. PJM, Midwest ISO, and ISO New England emphasize that their planning processes already provide for the evaluation and integration of demand response resources.²⁶⁵ Other commenters, such as Alcoa and Steel Manufacturer's Association, suggest that demand response resources be considered as substitutes for certain ancillary services.

470. In response to its notice convening the October 12 Technical Conference, the Commission received several comments addressing the role of demand response in planning. Participants in the technical conference generally responded that demand response programs are considered in planning, particularly in the load forecasts. Some observed that demand response has often been difficult to incorporate in long-term plans when it is not dispatchable and only available in one-year increments. Participants stressed that transmission providers must have control over a resource throughout the

²⁶⁵ See also ISO/RTO Council.

planning horizon if they are to rely on that resource in lieu of constructing upgrades. Some participants reported that this capability is available from several forms of demand response resources.

Commission Determination

471. The Commission adopts the NOPR's proposal and will require transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.²⁶⁶ In addition, transmission providers will be required to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied. This information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the

²⁶⁶ Much of the information should be available to those engaged in transmission planning already under reliability Standards TPL-001-0 through TPL-004-0 proposed in Docket RM06-16-000. See the Reliability Standards NOPR. These standards set out detailed requirements for annual studies to assess the performance of the transmission system and require conducting simulation studies over a five-year time horizon, with additional studies as needed for the six to ten-year horizon. The Commission proposed that planning entities conduct "studies to bracket the range of probable outcomes," examining system operation under variations in demand levels, existing and planned facilities, reactive power resources, generation dispatch and transaction patterns, controllable loads and demand-side management, and other factors. *Id.* at P 1047. While we recognize that OATT planning is distinct from these proposed reliability planning standards, we expect that the key data underlying transmission planning will be provided in conjunction with reliability standards and thus should be available for transmission planning when those standards are finalized.

incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion. We note, however, that transmission providers cannot be expected to fulfill these planning obligations unless non-public utility transmission providers that participate in the planning process make similar information available and, for the reasons set forth above, we fully expect that they will do so. We believe that the same safeguards developed as discussed above regarding the openness principle, such as confidentiality agreements and password protected access to information, will adequately protect against inappropriate disclosure of confidential information or CEII.

472. The Commission also requires that transmission providers make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies. It is important that the Commission, stakeholders, neighboring transmission providers, and affected state authorities have ready access to this information in order to facilitate coordination and oversight. To the extent any such information is confidential or consists of CEII, the transmission provider can implement the safeguards suggested above.

473. In response to the concerns of some commenters regarding the disclosure of information to non-public utility transmission providers, we believe that simultaneous disclosure of transmission planning information where appropriate alleviates many of those concerns. In those instances where there is non-simultaneous disclosure of information, we find that existing reciprocity requirements ensure that information is not

inappropriately shared with the non-public utility transmission provider's marketing affiliate.

474. In Order No. 888-A, the Commission clarified that, under the reciprocity condition, a non-public utility transmission provider must also comply with the OASIS and Standards of Conduct requirements or obtain waiver of them.²⁶⁷ We reiterate that non-public utility transmission providers should abide by the Standards of Conduct with regard to managing non-public transmission planning information obtained through the planning process, consistent with their reciprocity obligations. We also note that, given the planning process required by this Final Rule, it may be necessary to revisit the waivers of the Standards of Conduct granted to certain non-public utility transmission providers in the past. We will not do so, however, on a generic basis in this proceeding. All such existing waivers thus shall remain in place. Whether an existing waiver of the Standards of Conduct should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.²⁶⁸

475. In order for the Final Rule's transmission planning process to be as effective as possible, we emphasize that all transmission providers, both jurisdictional and nonjurisdictional, must be assured that the information they provide in that process will

²⁶⁷ See Order No. 888-A at 30,286.

²⁶⁸ We believe this same approach should also apply to public utilities that have obtained waivers of the Standards of Conduct.

not be used inappropriately in the wholesale power market. While we decline to require a third party independent facilitator as discussed below, we do believe that utilizing an independent entity may help parties manage Standards of Conduct concerns.²⁶⁹ Finally, we wish to emphasize that the Commission recognizes that compliance with the Standards of Conduct can impose costs on small entities, but we believe that this concern must be balanced against the fact that a coordinated and open transmission planning process is critical to remedying undue discrimination and meeting our Nation's future energy needs and that an open planning process cannot be fully successful if certain entities (whether jurisdictional or nonjurisdictional) can use the information to obtain an undue advantage in power markets. We therefore intend to balance the costs of confidentiality restrictions with the importance of not allowing any entity an undue competitive advantage in addressing this issue on a case-by-case basis.

476. Although we adopt the foregoing protections to ensure that particular entities do not gain an inappropriate competitive advantage over others, we believe that transmission providers should make as much transmission planning information publicly available as possible, consistent with protecting the confidentiality of customer information. Given

²⁶⁹ The Commission will consider whether further changes to the Standards of Conduct would facilitate the transmission planning requirement in the Standards of Conduct NOPR initiated in Docket No. RM07-1-000. See supra note 257. We also intend to address the concerns of NARUC with regard to waiving the Standards of Conduct concerning communications between resource and transmission planners in that proceeding.

that one of the primary objectives of the planning reforms adopted herein is to allow customers to consider future resource options, it will be necessary for market participants, including the merchant function of transmission providers, to have access to basic transmission planning information in order to consider those options. The simultaneous disclosure of transmission planning information can alleviate the Standards of Conduct concerns discussed above.²⁷⁰

477. In response to commenter concerns regarding the sufficiency of planning information currently available in the Form 715, we find that Form 715, as well as Form 714, have not provided customers and others with the timely data needed to perform load flow studies and other analyses to ensure that planning is being conducted on a comparable basis. For example, while we understand that certain planning information is already provided in FERC Form No. 714 (Annual Electric Control and Planning Area Report) and FERC Form 715 (Annual Transmission Planning and Evaluation Report), we believe that with regard to transparency of data and assumptions, Forms 714 and 715 are

²⁷⁰ Transmission providers could ensure simultaneous disclosure of information through such actions as providing all current and potential customers and other stakeholders equal access, notice, and opportunity to attend planning meetings, providing for the contemporaneous availability of meeting handouts and minutes on the transmission providers' OASIS or Internet websites, and requiring that an energy affiliate or marketing affiliate employee of the transmission provider may not attend a meeting unless a representative of at least one additional customer or potential customer is present. We believe such actions would typically constitute compliance with sections 358.5(a) and (b) of the Standards of Conduct, 18 CFR 358.5(a)-(b), dealing with information access and prohibited disclosure, respectively.

limited in a number of ways. An important limitation is that information is not necessarily available on a consistent geographic basis. Form 715 requires selected powerflow studies by control area, while Form 714 requires information on control area generation and load, including hourly load on a planning area. Since these two areas do not necessarily coincide, it can be difficult to apply the data except for the single annual or seasonal system peak. Consequently, Form 715 is an insufficient basis for broad transmission planning purposes and must be supplemented by additional assumptions and data.

478. Information may also be difficult to compare or apply if a region is larger than a single control area. Where the peak periods represented in the Form 715 correspond to different time periods in different control areas, separate assumptions and information may be needed for a study encompassing multiple control areas. In addition, each control area may include different criteria for including facilities in the data and additional assumptions will be needed to resolve these issues as well. Moreover, information on the basis for key assumptions is limited. The Form 715 instructions require a description of transmission planning reliability criteria and assessment practices, but allow the transmitting utility discretion on what is reported. As a result, assumptions regarding key inputs, such as the load forecasts, are not available. Similarly, information regarding customer demand response is not available. Lastly, Form 715 requires no information explaining the basis for generator dispatch in the powerflow cases, nor is any economic information provided. For studies of system peak reliability, when all generators are

expected to be running, this may not be a significant limitation. However, without some basis for dispatching the system at other times, it becomes difficult or impossible to conduct meaningful load flow studies for other planning purposes. Therefore, we will require the disclosure of criteria, assumptions, data, and other information that underlie transmission plans as described above.

479. Finally, several commenters assert that demand response resources should be considered in transmission planning.²⁷¹ Some commenters note that certain regions currently are in the process of incorporating demand response into their transmission planning processes.²⁷² Demand resources currently provide ancillary services in some regions, and this capability is in under development in some others.²⁷³ We therefore find that, where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should

²⁷¹ E.g., Ohio Power Siting Board, New Jersey Board, and WIRES.

²⁷² E.g., PJM and ISO-New England.

²⁷³ See Staff Report: Assessment of Demand Response & Advanced Metering at 97-100 (Docket Number AD-06-2-000) (Demand Response Report), available at http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0.

be permitted to participate in that process on a comparable basis.²⁷⁴ This is consistent with EAct 2005 section 1223.

d. Information Exchange

480. In the NOPR, the Commission proposed that network transmission customers be required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load. The Commission further proposed that point-to-point customers be required to submit any projections they have of a need for service over that planning horizon and at what receipt and delivery points. The Commission sought comment on whether specific requirements should be adopted for this information exchange.²⁷⁵ The Commission also stated that transmission providers must allow market participants the opportunity to review and comment on draft transmission plans.

²⁷⁴ The transmission planning processes we require in this Final Rule are not intended in any way to infringe upon state authority with regard to integrated resource planning. Rather, we believe that the transparency provided under an open regional transmission planning process can provide useful information which will 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.

²⁷⁵ The Commission noted in the NOPR that for network service, some of this information is already required by sections 29, 30, and 31 of the pro forma OATT, but to the extent it is not, the Commission proposed to require customers to provide additional information as necessary for the transmission provider to develop a system plan.

Comments

481. Transmission providers suggest that they should be responsible for developing a schedule and format for submission of information and the development of a draft plan that provides sufficient time for participants to review and comment before completion of a final plan.²⁷⁶ EEI emphasizes the importance of requiring comparable information from all participants in planning, including non-public utilities. EEI maintains that similarly-situated participants should have comparable information, with commercially-sensitive information available only to transmission function personnel. Duke supports the information exchange principle in general, but believes the NOPR envisions a wider exchange of information on loads and resources than is appropriate.²⁷⁷ Instead, Duke believes that planning participants should agree on how much detail will be available. WAPA similarly suggests that any criteria for information exchange should be developed by stakeholders, not the Commission.

482. Although commenters do not generally disagree with a requirement for point-to-point customers to submit projections of their needs for service, they question the value of these projections if the customers have not actually requested service for these

²⁷⁶ E.g., EEI, Pinnacle, Salt River, and Xcel.

²⁷⁷ TVA states that it is unaware of any shortcomings with the existing information exchange process and that more specific requirements may limit the ability of transmission providers to meet changing needs and processes.

projected needs.²⁷⁸ Nevada Companies state that point-to-point customers should provide future use forecasts and that the forecast data transferred by all entities should be provided for the planning horizon in a uniform manner.

483. Southern is concerned that the opportunity for review and comment could be construed to apply to draft interconnection, system impact, or facilities studies under the transmission provider's OATT. Southern argues that such a requirement would cause great delay and asks the Commission to clarify that the transparency requirement for review and comment on transmission plans is limited to only the transmission provider's draft of its base case transmission plan.

484. Other commenters advance a view that joint planning should consist of more than providing the transmission provider with information and then reviewing and commenting on the plans it develops; rather, customers need to be able to actively participate in the development of the planning studies and transmission plans.²⁷⁹ APPA likewise believes that earlier involvement is needed so that projected needs are fully understood and accounted for in the initial development of the plan.²⁸⁰ NCPA stresses that reviewing plans is meaningless if there is no access to data on how the plan was created, how economic evaluation was performed, and how and why proposed upgrades

²⁷⁸ E.g., APPA, Duke, and Salt River.

²⁷⁹ E.g., NCPA and TDU Systems.

²⁸⁰ See also Bonneville, California Commission, Imperial, NCPA, and Seattle.

were chosen. Old Dominion suggests that planning information and data be posted no less than monthly or, where appropriate, seasonally. TDU Systems and NCEMC stress that LSEs should have access to all information at the same time since if a transmission provider performs studies without including other LSEs, it opens the door for providers to act on sensitive information before releasing it to other LSEs.

485. Some commenters advance the view that distributed generation and other demand response resources should be considered in developing a transmission plan.²⁸¹

Commission Determination

486. The Commission adopts the information exchange principle as to both network and point-to-point transmission customers. Accordingly, we will require transmission providers, in consultation with their customers and other stakeholders, to develop guidelines and a schedule for the submittal of information. In order for the Final Rule's planning process to be as open and transparent as possible, the information collected by transmission providers to provide transmission service to their native load customers must be transparent and, to that end, equivalent information must be provided by transmission customers to ensure effective planning and comparability. We clarify that the information must be made available at regular intervals to be identified in advance. Information exchanged should be a continual process, the frequency of which should be addressed in the transmission provider's compliance filing required by the Final Rule.

²⁸¹ E.g., New Jersey Board, Ohio Power Siting Board, and WIRES.

However, we expect that the frequency and planning horizon will be consistent with ERO requirements.

487. We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. We believe that any good faith projections of a need for service, even though they may not yet be subject to a transmission reservation, may be useful in transmission planning as they may, for example, provide planners with likely scenarios for new generation development. If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests. To the extent applicable, transmission customers also should provide information on existing and planned demand resources and their impacts on demand and peak demand. In addition, stakeholders should provide proposed demand response resources if they wish to have them considered in the development of the transmission plan.

488. Lastly, in response to the concerns of some commenters, we emphasize that the transmission planning required by this Final Rule is not intended, as discussed earlier, to be limited to the mere exchange of information and then review of transmission provider plans after the fact. The transmission planning required by this Final Rule is intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers. At the same time, we

emphasize that this information exchange relates to planning, not other studies performed in response to interconnection or transmission service requests.

e. Comparability

489. In the NOPR, the Commission proposed that, after considering the data and comments supplied by market participants, each transmission provider develop a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning.

Comments

490. Several commenters support the comparability principle,²⁸² and others state that existing processes already follow this principle.²⁸³ EEI urges the Commission to emphasize that the “comparability” principle requires the transmission provider or transmission owner to treat similarly-situated participants comparably in the development of a plan, but does not require that all participants be treated equally. Pinnacle and others support comparable treatment of similarly-situated customers and request the Commission to confirm that native load protections will be recognized in the concept of comparability.²⁸⁴ New Mexico Attorney General asserts that native load and non-

²⁸² E.g., California Commission, NCPA, CREPC, Salt River, Seattle, and WAPA.

²⁸³ E.g., Duke and Imperial.

²⁸⁴ See also MidAmerican, Progress Energy, and Xcel.

affiliated merchants and other wholesale customers should not be treated comparably, because utilities have a statutory obligation to serve.

491. TDU Systems and the NRECA repeat the view that comparability cannot be achieved if the transmission provider is the only one developing the plan, which they believe this principle contemplates. They argue instead that LSEs should be allowed to participate actively in the development of the plan from the beginning and should have equal weight in decision-making. TDU Systems believes that comparability does not allow for different planning standards for certain customers, because it may leave rural electric cooperatives out of the planning loop.²⁸⁵ TAPS also argues that comparability is not enough; rather, substantive goals should be included.²⁸⁶

492. Noting that not all transmission service requests may be granted, Southern urges the Commission to clarify that the intent of this criteria is that the transmission provider plan its system so as to be able to reliably serve all of its long-term firm commitments on its transmission system in accordance with its state and federal legal requirements, as

²⁸⁵ See also NRECA Reply and Old Dominion.

²⁸⁶ TAPS cites to its "Balanced Principles for Transmission Planning & Expansion," which was attached to its NOI comments, for a description of the following substantive goals: (1) reliability/adequacy, (2) accommodating load growth, (3) preserving existing transmission rights, (4) access to regional competitive generation markets, (5) maintaining deliverability, (6) facilitating regional/inter-regional power transfers, and (7) integrating new generation into the regional grid. TAPS emphasizes that the process should anticipate needs and propose solutions before serious transmission problems emerge.

well as ERO Standards. With regard to RTO and ISO planning, NYAPP argues that it is not comparable for an RTO or ISO to only plan for bulk power facilities, while allowing individual transmission owners the discretion to plan for lower voltage transmission facilities.

493. Some commenters argue that demand resources should be treated comparably to other resources in transmission planning.²⁸⁷

Commission Determination

494. The Commission adopts the NOPR's proposal as to the comparability principle and will require the transmission provider, after considering the data and comments supplied by customers and other stakeholders, to develop a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning.²⁸⁸ Further, we agree with commenters that customer demand resources should be considered on a comparable basis to the service provided by comparable generation resources where appropriate.

²⁸⁷ E.g., ELCON, New Jersey Board, and WIRES.

²⁸⁸ As discussed above, we emphasize that the obligation imposed herein on transmission providers is meant to include transmission owners in RTOs and ISOs that no longer have their own OATTs, as well as non-public utility transmission providers required to comply with the Final Rule's planning process consistent with their reciprocity obligations.

495. We are specifically requiring a comparability principle to address concerns, such as those raised by commenters, that transmission providers continue to plan their transmission systems such that their own interests are addressed without regard to, or ahead of, the interests of their customers. Comparability requires that the interests of transmission providers and their similarly-situated customers be treated on a comparable basis. In response to the concerns expressed by several commenters, we emphasize that similarly-situated customers must be treated on a comparable basis, not that each and every transmission customer should be treated the same.²⁸⁹

f. Dispute Resolution

496. In the NOPR, the Commission proposed that transmission providers propose a dispute resolution process, such as requiring senior executives to meet prior to the filing of any complaint and using a third party neutral. The Commission noted that the Commission's Dispute Resolution Service is available to assist transmission providers in developing a dispute resolution process. The Commission also noted that, in addition to informal dispute resolution, affected parties would have the right to file complaints with the Commission under FPA section 206. The Commission sought comment on whether any specific dispute resolution processes should be required.

²⁸⁹ Additionally, in our discussion of the coordination principle above, we clarify that transmission planning is the tariff obligation of each transmission provider, and as such, ultimate responsibility for planning remains with transmission providers. Accordingly, we reject the arguments made by some commenters that comparability requires that customers have equal weight in decision-making.

Comments

497. Many commenters support the proposed dispute resolution principle,²⁹⁰ while others believe existing processes, including section 12 of the pro forma OATT, are sufficient.²⁹¹ Other commenters simply urge flexibility in the development of a dispute resolution process.²⁹² However, maintaining that the Commission has no legal authority to mandate a regional planning process or dispute resolution related thereto, Progress states the Commission should be flexible and allow for a voluntary dispute resolution process.²⁹³

498. Southern believes that dispute resolution should be limited to whether a provider has complied with any procedural requirements and not be utilized by parties to modify a transmission plan. APPA, however, argues that such an approach would relegate customers to an advisory role. EEI believes the Commission should include principles for dispute resolution and should allow stakeholders in the regional planning groups to craft their own procedures consistent with those principles. Reflecting concerns of some

²⁹⁰ E.g., APPA, Bonneville, California Commission, Imperial, and NCPA.

²⁹¹ E.g., East Texas Cooperatives, Salt River, Seattle, TVA and WAPA. TVA points out that since planning and its principles are just now being formed, resources would be better spent on developing platforms where interested parties could have input into the planning process, as opposed to dispute resolution.

²⁹² E.g., Allegheny, Nevada Companies, Pinnacle, and Southern. Xcel, however, does not believe any dispute resolution process is required in the OATT.

²⁹³ See also Duke and MidAmerican.

of its members, EEI cautions against mandating dispute resolution that includes binding resolution of whether, how, where, or when to construct additional transmission facilities.

499. Indianapolis Power believes there should be a dispute resolution process in place with specific steps identified, expressing reservations about the vagueness of the current MISO process. ATC argues that RTO plans should recognize which entity is ultimately accountable for building transmission, by requiring transmission customers that have a dispute with a plan first to appeal to the local transmission owner to ensure both entities fully understand what is being requested, before carrying the dispute further.

500. Consistent with its focus on integrated joint planning, TDU Systems asks that the Commission clarify that a dispute resolution process is not being required as a principle as an acknowledgement that transmission providers will retain control over the process. As long as LSEs are an integral part of the planning process, TDU Systems stress that there should be no need for an elaborate dispute resolution process.

Commission Determination

501. The Commission adopts the NOPR's proposal to require transmission providers to develop a dispute resolution process to manage disputes that arise from the Final Rule's planning process.²⁹⁴ An existing dispute resolution process may be utilized, but those seeking to rely on an existing dispute resolution process must specifically address how its

²⁹⁴ We have already addressed arguments concerning our jurisdiction to require a transmission planning process. A process for resolving disputes that arise from that planning process is a necessary incident to it.

procedures will be used to address planning disputes. The dispute resolution process should be available to address both procedural and substantive planning issues, as the purpose for including a dispute resolution process is to provide a means for parties to resolve all disputes related to the Final Rule's planning process before turning to the Commission.

502. We emphasize that the intent of the dispute resolution process required here is not to address issues over which the Commission does not have jurisdiction, such as a transmission provider's planning to serve its retail native load or state siting issues. As discussed above, however, we do intend that the planning process required by this Final Rule ensure comparability in planning between that conducted for a transmission provider's retail native load and its similarly-situated transmission customers and, therefore, issues relating to such comparability may be appropriate for the dispute resolution process.

503. Lastly, we encourage transmission providers, customers, and other stakeholders to utilize the Commission's Dispute Resolution Service to help develop a three step dispute resolution process, consisting of negotiation, mediation, and arbitration. Regardless of the process adopted by a transmission provider, affected parties of course would retain any rights they may have under FPA section 206 to file complaints with the Commission.

g. Regional Participation

504. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, the Commission proposed in the NOPR that each transmission

provider 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 “significant and recurring” transmission congestion (defined below). The Commission emphasized that such coordination should encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum. The Commission also recognized that, as in the West, it may be appropriate to organize regional planning efforts on both a sub-regional and regional level. The Commission sought comment on whether there are existing institutions (such as the NERC regional councils or sub-regional planning groups) that are well-situated to perform or coordinate this function.

Comments

Regional Scope

505. EEI agrees that regional planning should be encouraged, but urges the Commission not to be prescriptive about the size of the regions involved. According to EEI, the Commission should define regional planning as planning that involves more than one transmission provider and allow the regions to define themselves. CAISO believes the Commission should leave the determination of the sub-regional and regional boundaries to transmission providers. NC Transmission Planning Participants assert on reply that the participants in each regional process are in the best position determine the proper scope of the planning process for their region. NRECA argues that customers and

other stakeholders should be allowed to participate in the discussion that leads to the delineation of regions. NRECA asserts that regions should be large enough to minimize the potential for seams problems for LSEs in multiple control areas. At a minimum, NRECA argues that the Commission should ensure that all public utility transmission providers coordinate with their adjoining systems to ensure that the needs of LSEs with loads and resources in different systems' areas are met.

506. TDU Systems support mandatory regional planning and believe that the Commission should specify the criteria for determining regions, rather than prescribe regional boundaries. In TDU Systems' view, "regional" planning at a minimum means something more than planning on an individual control area basis.²⁹⁵ TDU Systems stress that the existence of sub-regional planning must not diminish the obligation to plan on a broader, more regional level. TDU Systems also believe that more than coordination is required; rather, transmission providers should be required to conduct planning on an integrated basis with, at a minimum, first-tier, adjacent interconnected systems. If a transmission provider refuses to do so, TDU Systems believe that should be considered an exercise of vertical market power and the transmission provider should lose its market-based rate authority. TDU Systems also urge the Commission to require regional

²⁹⁵ TAPS believes joint planning should include at least two transmission providers and be no smaller than a state. TAPS suggests that the transmission providers' compliance filings identify those other providers it proposes to include in its regular regional planning process.

planning for both reliability and economic upgrades, in order to ensure that competitive market development is not retarded by inappropriate seams at the borders of utility systems.²⁹⁶ In its reply, NRECA argues that regional participation must be mandatory, because uncoordinated, unilateral planning by transmission providers severely handicaps LSEs' assembly of competitive power suppliers for their customers.

507. PJM states that transmission providers bordering RTOs should be required to participate in the RTO planning process, but MidAmerican opposes such a requirement and believes it already happens in MISO anyway. MAPP also opposes such mandatory participation, pointing out that comparability would then require that transmission providers in RTOs participate in the planning processes of non-RTO providers on their borders as well.²⁹⁷ MAPP believes that currently-existing regions should have the opportunity to adjust their planning processes to meet the Commission's guidelines for regional transmission planning.

508. Indianapolis Power emphasizes that the regional scope of a transmission provider's planning process should consider grid topology and historical usage to avoid regions that are too broad or unwieldy. Indianapolis Power believes that the current MISO region may be an example of a region that is too large, but nevertheless asserts that

²⁹⁶ NRECA's comments on regional planning are consistent with those of TDU Systems.

²⁹⁷ See also MidAmerican Reply.

MISO should have the primary role in coordination, with regional councils in supporting roles. AWEA recommends nine planning regions that coincide with the nine regions being established for Regional Triennial Reviews in the market-based rate rulemaking in Docket No. RM04-7-000:²⁹⁸ PJM, New York, New England, Midwest, SPP, Southeast, California, Northwest, and Southwest.

509. LDWP and Salt River suggest that continued participation in existing regional and sub-regional groups should satisfy the expectation that municipally-owned transmission providers participate in open and transparent regional planning processes. Other commenters express a similar concern that the Commission not mandate any procedures that would interfere with the processes the West has already established.²⁹⁹ New Mexico Attorney General believes that those already engaged in a planning process should be allowed a waiver.

510. NARUC urges the Commission to clarify that planning proposals should not interfere with or undermine existing regional planning efforts, such as those conducted by

²⁹⁸ See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Notice of Proposed Rulemaking, 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 (2006).

²⁹⁹ Eg., California Commission, Imperial, and Salt River.

RTOs and in non-RTO areas.³⁰⁰ Project for Sustainable FERC Energy Policy recommends that the Commission use the Bonneville and PJM planning processes as models for evaluating transmission provider compliance. Arkansas Commission believes that the active involvement of states can be a catalyst for regional planning.

511. National Grid believes the principles of coordination, openness, and transparency should extend to inter-regional planning and requests clarification that this is the Commission's intent for neighboring regions in a single interconnect.

Existing Institutions

512. Regarding the Commission's request for comment on whether there are existing institutions that are well-situated to coordinate regional participation, commenters express differing views regarding the identity of the regional coordinator and the size of the region over which entities should be required to coordinate. Some transmission provider commenters cite NERC regions and regional councils as well-suited for coordinating regional participation.³⁰¹ Taking an opposite view, ISO/RTO Council maintains that RTOs and ISOs are the best models for regional participation, because

³⁰⁰ See also NC Transmission Planning Participants Reply and North Carolina Commission Reply. Also, in its reply, North Carolina Commission urges the Commission not to be overly prescriptive with respect to the details of regional transmission planning.

³⁰¹ E.g., Allegheny, Constellation, and Duke.

regional reliability organizations do not have mandates or authority to ensure that adequate system expansion occurs on a coordinated basis.

513. MISO is concerned the Commission intends to shift transmission planning responsibility from RTOs to the Regional Entities under the ERO, arguing that these entities have neither a sufficient level of independence nor a track record in transmission planning. TDU Systems suggest that RTOs, where they exist, should perform the regional planning function, although in some other instances it may be the regional reliability organizations. Although CAISO states that a larger regional entity with the authority to order expansion has some appeal, it contends there are too many hurdles to creating such an entity in the West. TAPS suggests a "Regional Joint Planning Committee" that is not dominated by transmission providers, which would direct the study process and be responsible for the development of uniform planning criteria, assumptions for base and changed cases, and transmission plans.

Existing Regional Planning Processes

The West

514. Transmission provider commenters in the West (outside California) generally recommend the Western Electricity Coordinating Council (WECC)³⁰² as a successful

³⁰² In general, WECC and its sub-regional groups have adopted an overall division of labor whereby WECC has undertaken facilitation of interstate, commercial transmission projects and the sub-regional groups have facilitated the planning of their member providers.

institution and an appropriate model for designating regions and developing a plan for the interconnection.³⁰³ Many public power entities and others in the West also support WECC and suggest that it should be a primary focus when deciding which institution can provide independent regional review and coordination of grid planning in the West.³⁰⁴ For example, California Commission notes that WECC's Transmission Expansion Planning Policy Committee allows for the consolidated needs of all the system operators in the Western Interconnection to be considered in the planning process and considers both reliability and economic transmission planning. California Commission also stresses that the processes in the West have resulted in transmission being built. Utah Municipals, however, are critical of the WECC process, and in reply, assert that the WECC process does not allow for effective stakeholder input, but merely review of transmission plans once they are formed. Utah Municipals also believe that sub-regional groups in its area (e.g., the Southwest Transmission Expansion Plan (STEP)) are more

³⁰³ E.g., ColumbiaGrid, MidAmerican, Nevada Companies, NorthWestern, Pinnacle, and Xcel.

³⁰⁴ E.g., Anaheim, APPA, California Commission, Imperial, LDWP, NCPA, PGP, Public Power Council, CREPC, Salt River, Santa Clara, Seattle, TANC, WAPA, and Western Governors. APPA notes, however, that not all of its members that support the WECC planning process support those within California.

effective and urges the Commission to focus on the effective implementation of joint plans.³⁰⁵

515. Other commenters support the sub-regional planning processes in the West as well, and generally believe the Commission should look to each sub-region's existing processes and institutions.³⁰⁶ For example, commenters in the Southwest and California also support the sub-regional groups located in that region (e.g., STEP and the Southwest Area Transmission Expansion Planning group (SWAT)).³⁰⁷ California Commission also supports the CAISO planning process and states that CAISO works closely with stakeholders to proactively identify needed, cost effective transmission solutions through an open, non-discriminatory process that has resulted in \$1.8 billion in transmission being

³⁰⁵ Public Power Council does not support expansion of WECC's role in coordinating planning beyond its current activities, as it believes WECC's strength lies in the area of reliability and not planning and, therefore, that WECC would be best served by focusing on reliability and standards enforcement, rather than as a participant (as a facilitator or otherwise) in commercial matters.

³⁰⁶ WAPA points out that certain broad functions related to planning can be coordinated at the regional level, but that sub-regional planning is necessary in an expansive regional area, such as WAPA's service territory, in order to provide focus and detail.

³⁰⁷ E.g., LDWP, New Mexico Attorney General, and Salt River. LDWP also cites its involvement in the Public Power Initiative of the West, CAISO, and the Western Arizona Transmission System group.

constructed.³⁰⁸ In its reply, NCPA emphasizes that the Commission should not equate the CAISO planning process with a California-wide process, because not all transmission providers in California are members of CAISO. However, California Commission notes that California, with the support of WECC, has begun the work of creating a California-wide sub-regional planning group that includes the large, unregulated municipal utilities that do not participate in CAISO.

Northeast

516. PJM, NYISO, and ISO New England all have transmission planning processes that have been approved by the Commission. ISO/RTO Council cites billions of dollars of transmission investment in the Northeast as an example of the success of these transmission planning processes and argues that these processes all satisfy the Commission's principles for coordinated, open, and transparent planning. PJM maintains that its Regional Transmission Expansion Planning Protocol is a successful and comprehensive regional planning paradigm. ISO New England also argues that its transmission planning meets the principles and further points to the Northeastern ISO/RTO Planning Coordination Protocol as providing coordinated planning across the entire Northeast region.

³⁰⁸ Anaheim believes that the CAISO process does not currently proactively evaluate the adequacy of the system or itself propose projects that will enhance reliability or efficiency and is based entirely upon plans presented to it by transmission owners. It notes, however, that CAISO has proposed reforms to address these issues. See also Anaheim Reply.

517. Utilities in the Northeast are generally supportive of the transmission planning in the Northeast RTOs. Designated NY Transmission Owners contend that the NYISO Comprehensive Reliability Planning Process is fully open, coordinated, and transparent and meets or exceeds each of the eight principles in the NOPR. PSEG believes the PJM planning process embodies the NOPR principles. Constellation cites the planning processes in PJM and the NYISO as examples of planning processes that, while not perfect, should serve as models for compliance filings by others. Old Dominion, however, expresses concern over continuing domination of transmission planning by transmission owners, but nevertheless commends PJM for recent efforts to include more stakeholder input in the planning process. National Grid is generally supportive of ISO New England's planning process.

Northwest

518. Several commenters in the Northwest generally support the Northwest Power Pool and the ColumbiaGrid process (which will provide for a biennial transmission expansion plan for certain entities in the Northwest).³⁰⁹ Also, two groups in the Northwest are forming to address sub-regional planning in that region – the ColumbiaGrid group and the Northern Tier Transmission Group – but it is not yet clear how such groups intend to coordinate with each other.

³⁰⁹ E.g., Bonneville, ColumbiaGrid, PGP, Public Power Council, and Seattle. APPA also notes its members' support for the sub-regional processes in the Northwest.

Southeast

519. The public power commenters in the Southeast were not as supportive of the existing regional and sub-regional planning processes in their region. TVA and Santee Cooper generally support the process conducted by the Southeast Electric Reliability Council (SERC), and Santee Cooper notes that it has had a formal joint planning process with its largest wholesale customer for more than 25 years. APPA, however, notes that its members did not generally endorse existing regional entities in the Southeast. APPA states that SERC, for example, just “rolls up” the transmission plans of the transmission providers and some working groups currently exclude non-transmission owners.³¹⁰

North Carolina

520. NCEMC points to the North Carolina Transmission Planning Collaborative (NC Transmission Planning), a joint planning process with an independent facilitator, in North Carolina. NCEMC emphasizes that more than regional coordination is required and that regional planning needs to be more than mere stakeholder review and must allow for full participation of LSEs in planning. NCEMC stresses that effective regional planning requires participation on a sufficient scale to encompass all LSEs within a natural market area in order to properly address seams issues and impacts on neighboring systems. Fayetteville does not believe NC Transmission Planning complies with the planning principles outlined in the NOPR.

³¹⁰ See also TDU Systems Reply.

Midwest

521. MISO believes its current transmission planning process represents industry best practices, arguing that it is open and inclusive and provides multiple opportunities for entities to participate. MISO Transmission Owners endorse the existing MISO transmission planning process and believe that the process already provides for regional planning and an open process with stakeholder involvement. Ohio Power Siting Board, however, claims that MISO's transmission planning process should not be regarded as best practices, stating that it is not sufficiently open and transparent. It also suggests that RTOs merely "rubber stamp" investor-owned utility plans. Additionally, FMPA³¹¹ notes that MidAmerican has recently made efforts to engage in more proactive planning and has offered joint transmission investment opportunities. FMPA also points to its membership in CAPX 2020, a consortium of Upper Midwest utilities, which are jointly studying and planning for the needs of regional transmission. However, FMPA makes clear that it believes smaller customers nevertheless need a tariff requirement for planning to ensure that their needs are addressed.

Florida

522. While the Florida Commission believes that the planning process conducted by the Florida Reliability Coordinating Council (FRCC) is adequate, others, such as FMPA, do

³¹¹ We note that FMPA filed joint comments on behalf of itself and the Midwest Municipal Transmission Group.

not.³¹² Florida Commission states that the FRCC has instituted a transparent and inclusive planning process whereby utilities, generators, and marketers participate in joint transmission planning studies and evaluate impediments to transfer capability and determine solutions to congestion in order to enhance the reliability of the FRCC system.

Commission Determination

523. We adopt the NOPR's proposal to include a regional participation principle as a component of the Final Rule's transmission planning process. Accordingly, in 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 or integrate new resources (discussed further below).³¹³

524. As discussed earlier in this Final Rule, since the advent of open access, power markets have become regional in almost every area of the country. These regional markets provide opportunities for wholesale customers to access competitive sources of

³¹² See also Seminole Reply.

³¹³ As provided for above, transmission providers will be required to file a "strawman" proposal for compliance with the Final Rule's planning process within 75 days after publication of the Final Rule in the Federal Register that includes, among other things, a specification of the broader region in which they propose to conduct coordinated regional planning. The Commission will then convene technical conferences in several broad regions around the country to assist the participants in developing the appropriate regional planning groups to the extent they do not already exist.

supply, rather than relying exclusively on local generation, including resources owned by their local transmission provider. However, as discussed above, it is not in the economic self-interest of transmission providers to expand the grid to permit access to competing sources of supply. A transmission provider has little incentive to upgrade its transmission capacity with its interconnected neighbors if doing so would allow competing suppliers to serve the customers of the transmission provider. We therefore find, as discussed in greater detail above, that greater coordination and openness in transmission planning is required, on both a local and regional level, to remedy undue discrimination. 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. The specific features of the regional planning effort should take account of and accommodate, where appropriate, existing institutions, as well as physical characteristics of the region and historical practices.

525. The Commission is encouraged that a number of voluntary coordinated and regional planning efforts have been developed throughout the country, including those administered by RTOs and ISOs and in certain sub-regions of the West and Southeast. For example, each of the Commission-approved RTOs in the Northeast, Midwest, and Southwest, as well as CAISO, provide for a coordinated and regional planning process with stakeholder input from each industry segment. There are several other promising efforts to establish voluntary coordinated and regional planning efforts around the

country as noted in our discussion above of existing regional planning processes.

526. The Commission fully supports these existing efforts and believes some of them are consistent in significant respects with the nature of the reforms adopted in this Final Rule. In those regions and sub-regions that already have adopted significant reforms, the Commission's planning reforms may require only modest changes, while other regions and sub-regions may need to undertake more significant changes to the way in which transmission currently is planned. The Commission will not in this Final Rule opine on the characteristics of existing regional planning processes or their consistency with the reforms we adopt today. Rather, each process will be addressed in the context of the relevant compliance filing. In general, however, the Commission urges participants in existing regional planning processes to closely examine whether improvements may be implemented to ensure that each regional planning process is fully consistent with the requirements of this Final Rule.

527. Finally, the Commission acknowledges the importance of identifying the appropriate size and scope of the regions over which regional planning will be performed. We agree that transmission providers, customers, affected state authorities, and other stakeholders should be involved in developing those regions. We decline to mandate the geographic scope of particular planning regions at this time. The scope of a particular planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions and sub-regions. In very large regions, there may well be both sub-regional and regional

processes. For example, in the West there are various sub-regional processes in addition to a WECC regional planning process. We believe that such an approach can work, provided that there is adequate scope to the sub-regional processes and adequate coordination between sub-regions. We expect sub-regions to coordinate as necessary to share data, information and assumptions as necessary to maintain reliability and allow customers to consider resource options that span the sub-regions.

528. In response to the commenters that indicate that regional planning already occurs today as part of the NERC planning process, we support any such processes, but reiterate that, if they are to meet the requirements of the Final Rule, they must be open and inclusive and address both reliability and economic considerations. As we discuss elsewhere in this section, customers must be allowed to request that economic upgrades be studied and, therefore, we will require transmission providers to coordinate on these issues as necessary in sub-regional or regional planning processes. To the extent the NERC processes are not considered appropriate for such economic issues, individual regions or sub-regions may develop alternative processes.

h. Economic Planning Studies

529. In the NOPR, the Commission proposed to require transmission providers to prepare studies identifying "significant and recurring" congestion and post such studies on their OASIS. The Commission explained that the studies should analyze and report on (1) the location and magnitude of the congestion, (2) possible remedies for the elimination of the congestion, in whole or in part, (3) the associated costs of congestion,

and (4) the cost associated with relieving congestion through system enhancements (or other means). The Commission sought comment on how to define “significant and recurring” congestion, such as by reference to generation redispatch, repeated denials of service requests, zero ATC, frequent curtailments or a combination of these factors. The Commission noted that the required congestion studies would address both “local” congestion (*i.e.*, within the transmission provider’s system) and congestion between control areas and sub-regions. The Commission stated that the purpose of this requirement is to ensure that affected market participants, state commissions, and the Commission understand both the costs of recurring transmission congestion and the alternatives for relieving it. The Commission sought comment on how this information should be used by transmission providers and market participants to address significant and recurring congestion.

Comments

Need for Congestion Studies

530. The Commission’s proposal regarding congestion studies gave rise to a wide range of comments. Some commenters generally support requiring congestion studies.³¹⁴ East Texas Cooperatives asserts that congestion studies will greatly assist in the development of transmission plans, enable planning participants to focus on key elements of the

³¹⁴ *E.g.*, APPA, Arkansas Commission, California Commission, East Texas Cooperatives, Entegra, NCPA, CREPC, Southwestern Coop, TDU Systems, and WIRES.

system and assist in the preparation of the congestion studies conducted by DOE. NRECA also supports requiring congestion studies, but urges the Commission not to be prescriptive.

531. Other commenters recommend eliminating the requirement.³¹⁵ Southern, for example, argues that congestion studies could be misleading because they can imply that all congestion needs to be remedied.³¹⁶ Duke, South Carolina E&G, and Southern agree that separate studies of congestion, beyond studies performed to meet service requests, should not be required. Rather than mandating congestion studies, Southern argues that the Commission should allow participants to determine which types of transmission studies have merit. Other commenters believe that, if congestion studies are required, they should be performed at a regional level rather than by each transmission provider individually.³¹⁷

532. The EEI position is representative of entities calling for elimination of the congestion study principle. EEI asserts that these studies in large part would be

³¹⁵ E.g., American Transmission, EEI, Progress Energy, and Southern.

³¹⁶ Entegra, however, replied to Southern's assertion that congestion studies can be misleading, stating that congestion studies did not need to be misleading, and were, on the contrary, necessary for customers to assess the costs of managing versus eliminating congestion.

³¹⁷ E.g., Imperial, MidAmerican, Nevada Companies, NorthWestern, Pinnacle, Salt River, SWAT, WestConnect, and Xcel.

duplicative of the studies being performed by DOE pursuant to EPCA 2005.³¹⁸ EEI also argues that these studies would be costly and time-consuming and that transmission providers generally do not have access to information needed for cost impact analysis and consequently cannot assess the cost of constraints.³¹⁹ TDU Systems assert on reply that it is difficult to imagine that providers do not have the information needed or means to determine the location and magnitude of congestion on their systems, since they perform this function for themselves already. TDU Systems add that customers will readily provide any information needed for congestion studies, as it is in their interest to do so. APPA believes that customers should be expressly required to produce information to help determine the cost of congestion (e.g., the additional cost to them of running or purchasing more expensive generation). TDU Systems also argues that the distinction between economic and reliability upgrades is a fiction and should be disregarded.

533. In the Western Interconnection, entities maintain that WECC will be performing congestion studies that should meet the requirement. As a result, they assert that this principle should not be applied to individual transmission providers in the West, but that these providers should be permitted to meet the principle through the interconnection-wide congestion studies conducted by WECC. Tacoma notes that ColumbiaGrid is

³¹⁸ Others assert that the DOE studies will be useful but not necessarily duplicative of the congestion study principle. E.g., APPA and Salt River.

³¹⁹ Bonneville agrees that the costs of congestion itself are not readily available to transmission providers and that customers are better positioned to determine this.

considering the services it can offer in congestion assessment at the sub-regional level in the Northwest. Other commenters, such as California Commission, Salt River, and Seattle, support a congestion studies requirement but believe it should not be required annually but rather biennially or triennially.

534. In the Eastern Interconnection, RTOs and ISOs, and entities in RTOs and ISOs, believe congestion studies are not needed where LMP markets are in place or are satisfied by RTO or ISO studies.³²⁰ Entergy argues that the congestion studies that will be performed by its independent coordinator of transmission should meet this requirement.

Determining "Significant and Recurring" Congestion

535. A variety of commenters provide suggestions as to what constitutes "significant and recurring" congestion. TDU Systems believe that there should be a presumption of congestion if a transmission provider posts zero ATC. TDU Systems, APPA, and Bonneville believe that other indications of significant and recurring congestion include the need for frequent generation redispatch, frequent curtailments for reasons other than force majeure, and repeated denials of requests for firm transmission service. California Commission and CREPC suggest a similar approach based on a comparison of ATC and schedules with historical flows and an assessment of denied requests, but emphasize that the process should be forward-looking as well.

³²⁰ E.g., Allegheny, FirstEnergy, Indianapolis Power, and PSEG.

536. APPA suggests the use of metrics to measure congestion (e.g., reporting on all congestion costs that exceed five percent of base energy costs and five percent of the hours in a season). California Commission also suggests the use of metrics, but cautions that there may be East-West differences. Sacramento stresses that such metrics should depend on whether the system being studied uses LMP or physical rights. In its view, financial metrics are most useful in LMP markets, while congestion in physical markets should be determined by paths that have been derated by a material percent of their nominal rating over a certain number of hours in a season.

537. Santa Clara suggests that significant and recurring congestion exists when congestion costs over a given path during the high use season approach or exceed the depreciation plus other fixed costs on the new facilities that would eliminate congestion on the path. Additionally, Santa Clara emphasizes that if, redispatch is necessary on an ongoing basis, this should be taken as an indication that new facilities need to be built.

538. New York Commission urges the Commission to utilize NYISO's process for measuring historical congestion – defined as the short-run production (i.e., dispatch) costs that could be avoided by system enhancements, as this represents the savings to society compared to the cost to society of investing in the system enhancement. New York Commission also cautions the Commission against using analyses focused on the impacts of transmission investments on wholesale energy prices, because these energy price impacts may be temporary and offset by changes in generation investments. TDU Systems and Old Dominion stress that in PJM significant and recurring congestion should

be based on total gross congestion and not the much smaller and unrealistic measure of unhedgeable congestion, as this masks the economic reality that congestion itself has an economic cost.³²¹

539. The Organizations of MISO and PJM States do not believe the Final Rule should address criteria for determining significant and recurring congestion, but should require each transmission provider to file criteria for inclusion and cost responsibility for upgrades that are included in the transmission plan to remedy congestion.

540. Seattle asserts that current OASIS standards do not support consistent tracking of service denials and that this inhibits the evaluation of congestion. Seattle also points out that the costs of congestion may be difficult to quantify because reliability dispatch is a reactive tool used only after service requests have been denied and prescheduled limits imposed and, therefore, foregone transactions will not be known to the transmission provider.

541. Ohio Power Siting Board asserts that distributed generation, demand response, and new technologies should be available to relieve congestion until longer-term solutions can be implemented.

Commission Determination

542. The Commission adopts the NOPR proposal and retains a congestion study principle as part of the Final Rule's transmission planning process; however, we modify

³²¹ See also Indicated Parties Reply.

and clarify the principle in certain important respects in response to the comments received. At the outset, we wish to clarify that our primary objective in adopting this principle is to ensure that the transmission planning process encompasses more than reliability considerations. Although planning to maintain reliability is a critical priority, it is not the only one. Planning involves both reliability and economic considerations. When 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. Such upgrades can, for example, reduce congestion (redispatch) costs or integrate efficient new resources (including demand resources) and new or growing loads. Thus, to represent good utility practice and provide comparable service, the transmission planning process under the pro forma OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process.

543. Some commenters argue that economic upgrades should be considered only in the context of individual requests for service under the pro forma OATT. The Commission disagrees. The process for addressing individual requests for service under the pro forma OATT is adequate for customers who request specific transmission rights to purchase power from a particular resource in a particular location during a defined time period. However, it does not provide an opportunity for customers to consider whether potential upgrades or other investments could reduce congestion costs or otherwise integrate new

resources on an aggregated or regional basis outside of a specific request for interconnection or transmission service. It thus limits, for example, groups of customers from considering more comprehensive solutions to transmission congestion, including investment in demand response. It also limits multiple LSEs from considering, on a more aggregated basis, whether particular upgrades may represent the most economic means of integrating new generation resources (e.g., wind resources) located in a common area that could be accessed by many customers. The Commission believes such coordinated studies can, for system planning purposes, be more beneficial than studies performed on a request-by-request basis. We also find that they are consistent with the requirement to provide comparable service. Transmission providers are not limited, in serving native load customers, to studying potential transmission upgrades only in the context of specific requests for service under the pro forma OATT.

544. Some transmission providers appear to object to this principle because they fear that an obligation to study potential upgrades is equivalent to an obligation to fund or build such upgrades. We clarify that this is not the intent of this principle. There is a difference between a planning process that is coordinated and open and one that dictates construction and cost responsibility. Both considerations are important, but, as we explain above, they are distinct. The purpose of this principle is to ensure that customers may request studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis (e.g., wind developers), not to assign cost responsibility for those investments or

otherwise determine whether they should be implemented. The issue of cost allocation is addressed in Principle No. 9 below.

545. The Commission also disagrees with the contentions of certain RTOs or ISOs that they need not comply with this principle. Although RTO and ISO planning processes tend to be more open and coordinated than the processes used by vertically-integrated transmission providers, this does not mean that RTO or ISO processes adequately address, in all circumstances, investments that are primarily economic in nature. When many RTO and ISO planning processes were created, they focused primarily on system enhancements necessary to maintain reliability. However, in recent years, as congestion has increased and generation reserve margins have declined, many RTOs and ISOs have taken increasingly progressive steps to identify investments that could reduce congestion and/or integrate new resources. For example, we recently approved a proposal by PJM to significantly enhance its RTEP planning process.³²² We applaud these efforts as consistent with the direction of the reforms adopted herein. However, we decline to provide a blanket exception for RTOs and ISOs. Each RTO or ISO must show that its planning process is consistent with or superior to the requirements of the Final Rule in all respects.

546. Some commenters express concern that this principle may result in costly congestion studies that are of little interest or value to customers. Our intent is not to

³²² See PJM Interconnection, L.L.C., 117 FERC ¶ 61,218 (2006), reh'g pending.

impose a costly study requirement that is unrelated to the real-world concerns of consumers. In the NOPR, we sought comment on whether specific metrics (e.g., zero ATC or TLR frequency) should be used to trigger the congestion study requirement. After considering the comments on this topic, we do not believe that any single metric, or group of metrics, is adequate for that purpose. Relying on discrete metrics in this instance would risk both over- and under-inclusiveness – i.e., triggering too many studies, thereby imposing cost burdens on transmission providers that are not appropriate, or triggering too few studies, thereby omitting important studies that could help customers identify cost-effective solutions to congestion. Additionally, we direct transmission providers, in consultation with their stakeholders during development of their Attachment K compliance filings (as discussed above), to develop a means to allow the transmission provider and stakeholders to cluster or batch requests for economic planning studies so that the transmission provider may perform the studies in the most efficient manner. We will also require the requests for economic planning studies, as well as the responses to the requests, be posted on the transmission provider's OASIS or web site, subject to confidentiality requirements.

547. The Commission will modify the principle to allow customers to choose the studies that are of the greatest value to them. Specifically, we are modifying the principle to require that stakeholders be given the right to request a defined number of high priority

studies annually (e.g., five to ten studies)³²³ to address congestion and/or the integration of new resources or loads. The intent of this approach is to allow customers, not the transmission provider, to identify those portions of the transmission system where they have encountered transmission problems due to congestion or whether they believe upgrades and other investments may be necessary to reduce congestion and to integrate new resources. The customers should be able to request that the transmission provider study enhancements that could reduce such congestion or integrate new resources on an aggregated or regional basis without having to submit a specific request for service. This approach ensures that the economic studies required under this principle are focused on customer needs and concerns, not administratively determined metrics that may bear no necessary relation to those concerns. Once such studies are requested, the transmission provider would conduct the studies, including appropriate sensitivity analyses, in a manner that is open and coordinated with the affected stakeholders. The cost of the defined number of high priority studies would be recovered as part of the overall pro forma OATT cost of service.³²⁴ By limiting this principle to a defined number of high priority studies annually, we are not precluding stakeholders from requesting additional

³²³ The example of five to ten studies mentioned in this Final Rule is merely illustrative. We recognize that the facts of each case will be used to determine the number of high priority studies allowed under a transmission plan.

³²⁴ This cost recovery mechanism is comparable and nondiscriminatory because the transmission provider already has the ability to include in its pro forma OATT rates the cost of service associated with studies performed on behalf of native load customers.

studies. However, to provide appropriate financial incentives, the stakeholder(s) requesting these additional studies would be responsible for paying the cost of such studies.

548. We also will modify this principle with respect to the scope of the studies being performed. The Commission proposed in the NOPR that the studies address "significant and recurring congestion." However, the Commission also sought comment on whether, in addition, the study process should address upgrades associated with new generation resources and provide information needed to proactively evaluate such resources. We discuss the comments on this proposal in more detail below, but, as described therein, we agree that the study process should incorporate such considerations. We therefore modify Principle No. 8 to encompass the study of upgrades to integrate new generation resources or loads on an aggregated or regional basis. This is appropriate because congestion can limit both the efficient dispatch of existing generation resources as well as inhibit the development of new supply and demand resources. Moreover, many regions of the country must make investments in the near future to meet load growth and, accordingly, studies of the most economic means of making such investments are critically important to consumers.

549. By expanding the scope of this principle, we do not intend to supplant the existing process for individual customers to integrate new resources or loads through specific requests for interconnection or transmission service under the pro forma OATT. Rather, we contemplate that any such studies conducted pursuant to this principle, as explained

above, would be for purposes of planning for the alleviation of congestion through integration of new supply and demand resources into the regional transmission grid or expanding the regional transmission grid in a manner that can benefit large numbers of customers, such as by evaluating transmission upgrades necessary to connect major new areas of generation resources (such as areas that can support substantial wind generation). Specific requests for service would continue to be studied pursuant to existing pro forma OATT processes.

550. With respect to studying the cost of congestion, several transmission providers argue that they do not have access to information regarding generation costs either from their merchant function or unaffiliated customers. We agree that the transmission provider should be obligated to study the cost of congestion only to the extent it has information to do so. We make clear, however, that if stakeholders request that a particular congested area be studied, they must supply relevant data within their possession to enable the transmission provider to calculate the level of congestion costs that is occurring or is likely to occur in the near future. To the extent that the transmission provider's merchant function possesses such information (e.g., redispatch cost information), it must provide that information to the extent necessary to conduct such studies. Providing for confidential treatment and application of the Standards of Conduct, as discussed above, will give assurance to customers that their cost and other information will not be used improperly. To that end, we direct transmission providers to

clearly define the information sharing obligations placed on customers in the planning attachment to their pro forma OATT.

551. In response to those commenters that argue that regional congestion studies should be sufficient, we agree that regional congestion studies can be used as part of regional transmission planning processes required by this Final Rule. For example, to the extent the DOE has extensively studied congestion in certain broad areas, it is not necessary or appropriate for transmission providers to duplicate these studies. However, regional studies typically provide broad information on overall regional power flows and may not provide sufficient detail on local system conditions and congestion, such as detail on congested local facilities that may limit customer supply options, or detail on local conditions where additional service could be provided through redispatch. Moreover, although the DOE may identify areas where congestion exists or new generation may be developed, the purpose of DOE congestion studies is not to develop specific transmission system plans to remedy such congestion or integrate such resources. The DOE studies are therefore not a substitute for a more open and coordinated planning process to address specific upgrades that could reduce congestion or integrate new resources and loads. We therefore require each transmission provider to comply with the revised economic planning studies principle in this Final Rule both as to its own transmission system and as to the regional planning process described above.

i. Cost Allocation for New Projects

552. In the NOPR, the Commission asked for comment on whether there should be a requirement for public utilities to develop cost allocation principles to address the recovery of costs associated with new transmission projects. In particular, the Commission asked whether the development of specific cost allocation principles would provide greater certainty and hence support the construction of new infrastructure or whether cost allocation is better handled on a case-by-case basis.

Comments

553. Several commenters express concern that the Final Rule not reopen cost allocation principles in RTOs and ISOs or in the OATTs of vertically-integrated transmission providers.³²⁵ Duke argues that the Final Rule should not address cost allocation for new transmission at all, stating that transmission pricing should be evaluated in a separate proceeding. Other commenters agree that cost allocation issues should be handled on a case-by-case basis.³²⁶

554. Some commenters urge the Commission to define cost allocation principles in this proceeding.³²⁷ For example, E.ON believes that the cost of upgrades should be directly

³²⁵ E.g., Duke, EEI, ELCON, ISO/RTO Council, MISO Transmission Owners, SCE, and Southern.

³²⁶ E.g., APPA, Arkansas Commission, PGP, Santee Cooper, Southwestern Coop, and Sacramento.

³²⁷ E.g., E.ON, National Grid and WIRES.

allocated to parties benefiting from an expansion and proposes that the host transmission owner should coordinate and be responsible for obtaining funding. Many transmission customers, however, support rolled-in cost recovery for network upgrades.³²⁸ TDU Systems ask the Commission to clarify that direct assignment of facility upgrade costs only applies to point-to-point service, unless it is being used for the delivery of designated network resources to serve network load. If direct assignment is retained, TDU Systems suggest the Commission consider standardizing directly assignable facilities on a regional basis and stress that the critical factor is comparability. TAPS suggests "regional" cost-spreading for backbone high voltage facilities and criticizes participant funding because it encourages would-be beneficiaries to wait and hope that others will step forward first.

555. Old Dominion emphasizes the need for cross-border transmission cost allocation mechanisms. In joint projects, Salt River emphasizes that it is inconsistent with an open season approach to assign benefits to a party and then assign cost responsibility beyond what the project participant would voluntarily assume based on the subscription rights received. Both Bonneville and TVA believe that cost allocation principles should be based on a determination of beneficiaries and cost causation. New Mexico Attorney General stresses that cost recovery for construction of transmission intended for wholesale or market transactions should not be allocated to native load. NCPA states that

³²⁸ E.g., AWEA, NCEMC, NCPA, NRECA, Seattle, and TDU Systems.

it would expect some Commission deference to recovery of costs of projects identified in a truly collaborative process.

556. At the October 12 Technical Conference, PJM stated that the Commission should provide generic guidance on what would be acceptable regarding cost allocation, though Progress Energy did not favor putting a cost allocation approach in the pro forma OATT, as modified by the Final Rule. National Grid expressed the view that the Commission would need to address cost allocation generally, arguing that cost allocation solely on a project-by-project basis is inefficient.

Commission Determination

557. The Commission finds, after considering the comments, that it is appropriate to include a specific principle regarding cost allocation. The manner in which the costs of new transmission are allocated is critical to the development of new infrastructure.

Transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. We therefore find that, for a planning process to comply with the Final Rule, it must address the allocation of costs of new facilities.

558. The Commission emphasizes, however, that we are not modifying the existing mechanisms to allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structures. Our intent is not to upset existing cost allocation methods applicable to specific requests for interconnection or transmission service under the pro forma OATT. The cost allocation principle discussed herein is

intended to apply to projects that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the study process described above, rather than through individual requests for service. We will not impose a particular allocation method for such projects, but rather will permit transmission providers and stakeholders to determine their own specific criteria which best fit their own experience and regional needs. The proposal should identify the types of new projects that are not covered under existing cost allocation rules and, therefore, would be affected by this cost allocation principle.

559. Although the Commission does not prescribe any specific cost allocation method in the Final Rule, we believe some overall guidance is appropriate. Our decisions regarding transmission cost allocation reflect the premise that "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."³²⁹ We therefore allow regional flexibility in cost allocation and, when considering a dispute over cost allocation, exercise our judgment by weighing several factors. First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region.

³²⁹ Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945).

560. These three factors are interrelated. For example, a cost allocation proposal that has broad support across a region is more likely to provide adequate incentives to construct new infrastructure than one that does not. The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly. Similarly, a proposal that allocates costs fairly to participants who benefit from them is more likely to support new investment than one that does not. Adequate financial support for major new transmission projects may not be obtained unless costs are assigned fairly to those who benefit from the project.

561. These factors are particularly important as applied to the economic upgrades discussed above – e.g., upgrades to reduce congestion or enable groups of customers to access new generation. As a general matter, we believe that the beneficiaries of any such project should agree to support the costs of such projects. However, we recognize that there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it. In the past, different 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. We believe that a range of solutions to this problem are available. We therefore continue to believe that regional solutions that garner the support of stakeholders, including affected

state authorities, are preferable. Moreover, it is important that each region address these issues up front, at least in principle, rather than having them relitigated each time a project is proposed. Participants seeking to support new transmission investment need some degree of certainty regarding cost allocation to pursue such investments.

3. Additional Issues Relating to Planning Reform

a. Independent Third Party Coordinator

562. In the NOPR, the Commission acknowledged that an independent third party coordinator would provide benefits for transmission planning, but did not propose to require independence. Noting that independence could take many forms, the Commission sought comment on the level of independence that could provide benefits and the institutions that could offer such independence.

Comments

563. Overall comments on the use of an independent third party to oversee or coordinate the planning process range from those who believe it is not needed to those who feel that it should be required rather than merely encouraged. Arguing against the need for an independent coordinator, South Carolina E&G does not believe an independent third party is either necessary or desirable. Arguing in favor of an independent coordinator, EPSA strongly supports independent oversight and believes that third party oversight will be necessary in non-RTO areas, particularly where transmission

such as retail resource needs, in the planning process.³³⁸ As with any other interested stakeholder, we emphasize that planning must be coordinated with relevant state regulators (including city councils, local siting boards, and other agencies) that wish to participate in the transmission provider's planning process. We will not prescribe a particular level of state participation, but rather encourage states to determine their own level of participation, consistent with applicable state law.³³⁹ We stress that state determinations with respect to retail load will not be second-guessed, but that once those determinations are incorporated into the transmission plan, the transmission planning principles will apply (e.g., for purposes of determining whether similarly-situated customers are treated comparably).

575. Just as we intend to coordinate with state regulators and other agencies, we also encourage those parties to collaborate amongst themselves as well, particularly regionally, in order to reach agreement on how best to review and approve new transmission facilities that are the product of the coordinated and regional planning

³³⁸ As noted above, we expect the concerns of NARUC and others that the application of the Commission's Standards of Conduct are inhibiting state resource planning will be addressed in the rulemaking proceeding on the Standards of Conduct in Docket No. RM01-7-000. See supra note 257.

³³⁹ We also recognize that there are concerns about how state regulators and other agencies will recover the costs associated with their participation in the planning process. As discussed below, we direct transmission providers to propose a mechanism for cost recovery in their planning compliance filings. These proposals should include relevant cost recovery for state regulators, to the extent requested.

process required by this Final Rule. We intend to defer to such agreements between state regulators and other agencies in a given region as appropriate. We are, moreover, sensitive to concerns, such as Allegheny's, about the overlapping nature of regulatory jurisdiction over planning matters. We believe the planning principles in this Final Rule will help alleviate this concern by facilitating coordination through open, transparent planning and enhanced exchange of information. We also understand Santa Clara's concern that certain state regulators do not represent all energy consumers in some states; however, we do not believe this detracts from the significant interest that state regulators and other agencies have with regard to transmission planning for their state and region.

c. **Flexibility in Implementation and Examples of Compliant Processes**

576. In the NOPR, the Commission sought comment on how much flexibility the transmission provider should be given in implementing the principles and requested examples of transmission planning processes that comply with the proposed principles.

Comments

577. Commenters generally favor flexibility and urge the Commission not to be too prescriptive regarding how the planning processes must satisfy the planning principles. Many entities in the Western Interconnection cite the overall WECC process as largely compliant with the principles. Nevada Companies notes that the WECC process works well under the existing pro forma OATT, so that few changes should be required to implement the proposal. In the East, Progress Energy and Duke cite NC Transmission

Planning as an example of an effective planning process that generally meets the principles.

578. Constellation agrees with providing flexibility, but believes the Commission should strongly encourage transmission providers to model their compliance filings after existing processes, such as those in RTOs and ISOs. ISO/RTO Council and all individual RTOs and ISOs argue that their processes are generally compliant and should not be disturbed. Transmission providers in RTOs and ISOs generally support this position.³⁴⁰

579. Some entities believe that flexibility should be permitted in order to deal with regional variations, but that individual transmission providers should have limited flexibility in implementing the planning process.³⁴¹ Some commenters simply state that regional flexibility should be permitted, without further elaboration.³⁴² Other commenters urge the Commission to limit both regional and local flexibility.³⁴³

580. NRG argues that system planning models should reflect economic dispatch to facilitate efficient utilization and also argues in favor of requirements for specific criteria on the treatment of system overloads and contingencies. AWEA proposes a specific regional planning protocol patterned off the "Collaborative Governance" model

³⁴⁰ E.g., Allegheny, Duke, and National Grid.

³⁴¹ E.g., APPA, East Texas Cooperatives, Seattle, and TDU Systems.

³⁴² E.g., Bonneville, Salt River, PJM, and TVA.

³⁴³ E.g., Arkansas Municipal, Project for Sustainable FERC Energy Policy, and Southwestern Coop.

developed during mediation for the Southeast RTO in Docket No. RT01-100.

581. In reply to commenters arguing in favor of less flexibility, Indianapolis Power maintains that its experience in MISO shows that flexibility is needed, citing the wide variations within the MISO footprint and the difficulties experienced in planning for a single large region. MidAmerican opposes the NRG proposal for regional modeling standards, as well as the AWEA proposal for a regional planning protocol, as too burdensome. Exelon expresses general agreement with the EEI position on flexibility, but states that planning processes outside RTOs do not presently meet the NOPR's requirements. Exelon states planning processes outside RTOs should follow the planning direction of RTOs like PJM.

Commission Determination

582. Although we allow flexibility in the development of a coordinated and regional planning process, the Commission will carefully review transmission planning compliance filings to ensure that each planning process is consistent with the planning principles and other requirements in this Final Rule. We encourage transmission providers to give consideration to existing planning processes, such as those already implemented by ISOs or RTOs, or those proposed by AWEA, as they work with their customers and other stakeholders to develop a transmission planning process that complies with the Final Rule. The Commission makes clear, however, that we do not endorse any specific existing process as a model for all transmission providers.

opposing mandatory hourly service raise a number of legitimate concerns with respect to the service's potential to adversely affect reliability and create additional complexity and inefficiency in scheduling and administering the right of first refusal. We do not believe that the modifications suggested by commenters supporting the service adequately resolve these concerns. Given regional differences and varying system constraints, a solution that may be appropriate for resolving scheduling, reservation or other issues resulting from hourly firm service on one transmission system may not be appropriate for another transmission system. Moreover, even the commenters supporting the proposal do not demonstrate a clear need for an hourly firm service product. The Commission therefore concludes that requiring hourly firm service is not needed to address undue discrimination, the goal of this rulemaking.

1213. To the extent they deem it appropriate, transmission providers will continue to have the option to propose offering hourly firm service in an FPA section 205 filing with the Commission. Because we are not adopting the mandatory hourly firm service proposal, we believe that the most serious concerns regarding scheduling short-term service and administering the right of first refusal are alleviated. We address scheduling and right of first refusal issues relating to existing services in section V.D.5.b.

3. Rollover Rights

1214. Section 2.2 of the pro forma OATT allows existing firm transmission service customers – wholesale requirements and transmission-only customers with contracts of one year or more – the right to continue to take transmission service from the

transmission provider when the customer's contract expires. The pro forma OATT provides that the transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the transmission provider or elects to purchase capacity from another supplier. This transmission reservation priority for existing firm transmission service customers, which is also referred to as a right of first refusal or a rollover right, is an ongoing right that currently may be exercised at the end of all firm contract terms of one year or longer. A transmission customer must give notice of whether it will exercise its right of first refusal 60 days before the expiration of its service agreement.

1215. In Order No. 888, the Commission provided that, if a transmission customer subject to the rollover right selects a new power supplier that substantially changes the location or direction of its power flows, the customer's right to continue taking service from the transmission provider may be affected by transmission constraints associated with the change.⁷³² The Commission also provided that a transmission provider may reserve existing capacity for retail native load and network load growth reasonably forecasted within the transmission provider's current planning horizon, but that any capacity so reserved must be posted on the transmission provider's OASIS and made available to others until the capacity is needed for the anticipated network or retail native

⁷³² Order No. 888 at 31,665 n.176.

load use.⁷³³ The Commission also has held that a transmission provider may restrict a right of first refusal based on pre-existing contracts that commence in the future if the transmission provider knows at the time of the execution of the original service agreement that ATC used to serve a customer will be available for only a particular time period, after which time it is already committed to another transmission customer under a previously confirmed transmission request.⁷³⁴ Once a transmission provider evaluates the impact on its system of serving a long-term firm transmission customer and grants the transmission customer existing capacity, the transmission provider must plan and operate its system with the expectation that it will continue to provide service to the transmission customer should the transmission customer exercise the right of first refusal. If constraints arise after a transmission provider enters into a long-term agreement with the transmission customer (and that agreement does not contain an allowed restriction on the transmission customer's right of first refusal), the obligation is on the transmission provider to either curtail service to all affected customers or build more capacity to relieve the constraint.⁷³⁵ A transmission provider is obligated to curtail service pursuant to its OATT or expand its system when its system becomes constrained such that it cannot satisfy existing transmission customers, including the exercise of their rollover

⁷³³ Id. at 31,694.

⁷³⁴ E.g., Southwest Power Pool, Inc., 109 FERC ¶ 61,041 at P 6 (2004).

⁷³⁵ Id. at P 9.

rights, because it should have planned and operated its system with the expectation that each long-term firm transmission customer will exercise its rollover rights.⁷³⁶

1216. If a transmission provider's transmission system cannot accommodate all of the requests for transmission service at the end of the contract term, the existing long-term transmission customer must agree to match the rate offered by the potential customer, up to the transmission provider's maximum rate, and to accept a contract term at least as long as that offered by the potential customer. However, a competitor's offer does not have to be "substantially similar in all respects" to the existing transmission customer's.⁷³⁷

NOPR Proposal

1217. In the NOPR, the Commission proposed to revise the right of first refusal provision in the pro forma OATT to apply to firm wholesale requirements and transmission-only contracts that have a minimum term of five years, rather than the current minimum term of one year. In addition, a transmission customer under a rollover agreement would be required to provide notice of whether it intended to exercise its right of first refusal no less than one year prior to the expiration of its contract, rather than the current 60 days. The Commission proposed to maintain the requirement that an existing transmission customer match competing offers as to term and rate. The Commission

⁷³⁶ Id.

⁷³⁷ Idaho Power Co. v. FERC, 312 F.3d 454, 462 (D.C. Cir. 2002).

discussed whether native load restrictions should be reevaluated with each rollover and, if so, whether native load should then be required to compete with rollover customers for the capacity. The Commission also asked for comment on whether there is a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis to address the need for a transmission provider to demonstrate its forecast of native load growth and its effect on capacity reserved by rollover customers. The rollover reforms were proposed to be effective as to new transmission contracts upon Commission acceptance of the transmission provider's coordinated and regional planning process required by the Final Rule, with existing rollover contracts becoming subject to the new rules on the first rollover date after the effective date of the revisions.

a. **Five-Year Minimum Contract Term**

Comments

1218. Many commenters support the increase in the contract term eligible for a rollover right.⁷³⁸ These commenters support the increase to five years based largely on the

⁷³⁸ E.g., APPA, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, EEL, Entegra, Entergy, E.ON, FirstEnergy, Great Northern, Imperial, Indianapolis Power Reply, LPPC, LDWP, MidAmerican, MISO, MISO Transmission Owners, Nevada Commission, Nevada Companies, North Carolina Commission Reply, Northwest IOUs, NorthWestern, NPPD, PGP, Pinnacle, PNM-TNMP, Progress Energy, Public Power Council, Sacramento, Salt River, Santa Clara, Seattle, South Carolina E&G, Southern, SPP, Tacoma, TAPS, TransServ, TVA, Utah Municipals, and Xcel. The Commission notes that several of these commenters have conditioned or qualified their support on the adoption of a number of modifications, which will be discussed below.

Commission's rationale for proposing it, i.e., an increase to five years would encourage longer-term use of the grid and assist in long-term planning. Many also point out that a longer minimum term reduces the universe of contracts transmission providers must assume will exist in perpetuity, thereby increasing certainty and reducing speculation. These commenters also argue that rollover reform will improve reliability and provide increased revenues to perform upgrades. Some also argue that this is consistent with the native load protections in new section 217 of the FPA.

1219. E.ON, for example, notes that system expansions may have been limited in the past because transmission providers did not want to commit resources to accommodate a service guaranteed for only one year, and Xcel and TVA note that the increase in term should encourage investment and expansion of the grid by providing improved certainty of cost recovery. EEI stresses that there is no single minimum rollover term that works for all parties, as power purchase contract terms vary and some state planning obligations require purchases for longer or fewer than five years, but that five years represents a reasonable balance. Southern emphasizes that the reforms should also improve reliability, promote the provision of service to native load transmission customers, and increase market efficiencies by releasing transmission capacity to the market. In its reply, Southern expresses its belief that the current policy of requiring transmission planners to assume that all agreements having a minimum term of one year will continue taking service in perpetuity threatens reliability. In Southern's view, this policy results in planning that is based on speculation and guesswork that can signal a need for

inappropriate and expensive transmission upgrades and mask the need for appropriate expansion.

1220. However, several modifications and clarifications were sought by some commenters before they could agree to an increase in the minimum term to five years. APPA, Sacramento, and TAPS contend that transmission customers making this long-term commitment should be permitted to change their designated resources and receipt points as their power supply needs change.⁷³⁹ APPA also asserts that transmission customers that agree to a five-year contract term should not be forced to compete with other transmission customers for firm capacity whenever their contracts come up for renewal. Without such assurances of continued service, APPA argues that the Commission's proposals would not comport with section 217 of the FPA.⁷⁴⁰

1221. In order to further ensure continued service, TAPS seeks the following modifications: transmission providers should be required to redispatch if necessary to accept a "reasonably foreseeable" and timely designated network resource with costs shared on a load ratio basis; transmission providers should be required to offer cost-based sales to embedded transmission-dependent utilities that cannot reach alternative suppliers; and exceptions should be permitted to the five-year minimum term and

⁷³⁹ See also TDU Systems Reply.

⁷⁴⁰ See also NCEMC and Arkansas Municipal (opposing the increase in the minimum term to five years).

matching exposure for small embedded transmission-dependent utilities and full or near-full requirements customers to ensure a continued right to service. Additionally, TAPS asserts that the minimum rollover in the absence of a competing request should be one year, rather than five.

1222. TDU Systems, which generally opposes the increase to five years, believe that the Commission should clarify that rollover customers retain their rights to transmission capacity in the event of competing bids from either the transmission provider or another transmission customer if the rollover customer matches up to a five-year contract term. Lastly, Seattle is concerned that with a five-year minimum, the risk in multi-segmented transmission transactions of one segment being undone by refusal of another is increased. Seattle suggests that acceptance and confirmation of one segment be made contingent on coordinated acceptance and confirmation on all other required segments.

1223. In its reply to the arguments that rollover rights should be extended to accommodate service at new receipt or delivery points, EEI argues that this would allow a rollover customer to have priority over higher-queued customers on transmission paths other than the path over which the rollover customer is currently taking service, even if the new service would have different impacts on the transmission system. EEI argues that such service would be new service and not a rollover of existing service. EEI also urges the Commission to reject TAPS' assertion that it should require the transmission provider to accept rollover customers' designations of any network resources that are reasonably foreseeable and to redispatch its system if necessary to accommodate that

resource, because among other things this would require providers to build the transmission system with sufficient redundancy to permit any customer to take service from any resource. Moreover, EEI argues that TAPS does not provide any suggestion as to what should be considered a reasonably foreseeable resource and that sharing costs on a load ratio basis would result in eighty to ninety percent of the redispatch costs being borne by the transmission provider's native load customers.

1224. EEI also argues in its reply that TAPS' proposal to exempt all small customers from the five-year minimum term would interfere with transmission providers' ability to plan their systems to meet their customers' needs, as the aggregated loads of several small customers can have a substantial impact on the system. EEI contends that TAPS' proposal to exempt all full and near-full requirements customers is also unreasonable, as the transmission provider would be forced to provide preferential service to certain groups of customers. As for the proposal to allow customers to exercise rollover rights with only one-year contracts if there is no competing request, EEI contends there is no need for a rollover if there is no competing request, since there is enough capacity for all and the transmission provider will grant the customer's new request for service for one year.⁷⁴¹

⁷⁴¹ In their replies, Entergy, MidAmerican, and Progress Energy note many of these same concerns.

1225. The increase in the minimum contract term eligible for a rollover right was opposed outright by several commenters for a variety of reasons.⁷⁴² Many of these commenters oppose the increase to five years because they claim it is difficult under current market conditions to secure a five-year power supply agreement to underpin a five-year transmission contract, particularly in organized markets where the focus is on spot transactions or where the grid is very weak.⁷⁴³ They also argue that changes in the market (e.g., fuel costs) could significantly change the options available to customers within a five-year period and that a service extension of less than five years may be needed to manage delays in generation construction or some other unforeseeable event. TDU Systems urge the Commission to require any transmission provider seeking an increase in the minimum contract term to demonstrate that sufficient economic power supplies are available under longer-term contracts. EEI replies that such an approach would be inconsistent with the separation of functions between generation and transmission.

⁷⁴² E.g., Alberta Intervenors, Alcoa, Ameren, AMP-Ohio, Arkansas Municipal, AWEA, Dynegy Reply, Eastern North Carolina, EPSA, Exelon, Fayetteville, Manitoba Hydro, Morgan Stanley, NCEMC, NRECA, MISO/PJM States, PJM, Powerex, PPM, Reliant, TDU Systems, TransAlta, Williams, and Wisconsin Electric.

⁷⁴³ E.g., Alcoa, AMP-Ohio, Arkansas Municipal, AWEA, Eastern North Carolina, EPSA, Exelon, Fayetteville, Manitoba Hydro, NCEMC, NRECA, MISO/PJM States, Reliant, TDU Systems, and Wisconsin Electric. TAPS also notes the difficulties, particularly for small transmission-dependent utilities, of locking in a five-year supply contract a year in advance of rollover.

1226. Some commenters also argue that five years is incompatible with retail procurement processes in some states, such as Illinois and New Jersey, which they assert limit power supply agreements to three years.⁷⁴⁴ AWEA and PPM suggest that the Commission increase the minimum term to three years, because five years is beyond the term for many shorter-term power sales transactions and it would be cost prohibitive to lock up service for five years. Manitoba Hydro suggests a two to three-year minimum term and that guaranteed redirects be permitted. Constellation, while generally supportive of a five-year minimum term, would prefer a three-year minimum term because it says three years is more closely aligned with much of the commercial activity in the energy commodity markets. Wisconsin Electric supports the current one-year term, but proposes three years as an alternative. In its reply, Duke indicates that it would support a three-year minimum term for rollover, but only if the notice period is required to match project lead time.

1227. In their replies, several commenters dispute the assertion that customers may not be able to obtain generation supplies for five-year periods. They contend that generators in a competitive market will have to offer five-year contracts or risk losing their sales if LSEs begin requesting five-year contract terms in order to obtain rollover rights.⁷⁴⁵ SPP states on reply that it has not been its experience that suppliers have refused to enter into

⁷⁴⁴ E.g., EPSA, Exelon, Reliant, and MISO/PJM States.

⁷⁴⁵ E.g., EEI Reply and Southern Reply.

power supply agreements in excess of three years. EEI also argues that, even if a transmission customer has to accept the risk that its term of service exceeds the term of its power purchase in order to obtain rollover rights, the cost of the transmission service that is at risk is small in comparison to the cost of the power because the cost of transmission service is only a small portion of the delivered price of energy. EEI and Bonneville also note in their replies that unneeded transmission service can be sold in the secondary market.

1228. NCEMC opposes the increase in contract term because it would inhibit the ability to pursue its prudent portfolio approach to mitigate price risks by providing for a mix of shorter and longer-term power supply contracts. If the Commission increases the minimum term, NCEMC argues that all existing rollover contracts should be grandfathered. EPSA also believes that existing one-year contracts should be grandfathered, otherwise it argues that market participants that relied on the current policy will be harmed. In its reply, EEI urges the Commission to reject EPSA's proposal that all currently effective one-year power supply contracts be grandfathered because, in EEI's view, it would interfere with good utility planning. EEI also argues that extending the minimum term to five years does not abrogate a customer's power supply contract because transmission and supply are unbundled and, therefore, changing the terms of transmission service does not interfere with contract rights under power sales agreements.

1229. Exelon argues that limiting rollover rights to contracts that are five years or greater will discriminate against merchant generators that do not have load linked to generation,

lead to stranded generation investments that were based on the current rules, and unfairly advantage local utilities wanting to build their own generation as opposed to seeking competitive alternatives. Exelon suggests that an approach similar to that utilized in PJM be adopted, in which PJM evaluates new requests for service that cannot be granted without utilizing an existing customer's service by notifying the existing customer and requiring it to match the new request within thirty days or release the service. PJM explains further that its approach would allow transmission customers two rollover options: long-term service for less than five years with no rollover right, or service for one year with indefinite rollover rights conditioned on either future limitations or an agreement to pay for necessary upgrades to maintain the rollover. In its reply, TAPS opposes the PJM approach stating that it would invite discrimination by transmission owners.

1230. Other commenters that oppose the increase to five years assert that they are already long-term customers that simply take service year-to-year and should therefore already be included in planning, based on the fact that they are either a generator or load and cannot simply pick up and leave the system.⁷⁴⁶ Several other commenters likewise oppose the increase to five years because they do not believe that it will result in an increase in long-term contracting and planning as suggested by the Commission.⁷⁴⁷ For

⁷⁴⁶ E.g., Morgan Stanley and Manitoba Hydro.

⁷⁴⁷ E.g., Alberta Intervenors, TransAlta, and Williams.

example, Williams notes that it currently has a ten-year transmission contract and argues that its transmission provider has done nothing to improve the grid in its area. TransAlta believes that a five-year minimum contract term will limit market participation to deep-pocketed market participants who can afford long contracts. TransAlta also believes that the current option to contract for just one year and obtain a rollover right is often the benefit that prompts market participants to buy yearly service instead of shorter-term products and, therefore, is an incentive to purchase longer-term service. Alberta Intervenors believe that a longer minimum term will provide a disincentive for long-term trading since the increased time commitment of five years will significantly increase the trading party's risk.⁷⁴⁸ The Organizations of MISO and PJM States believe that the current rollover policy generally results in an increase in investment in transmission and is only detrimental if service is terminated and the capacity goes unused.

Commission Determination

1231. The Commission finds that the current rollover policy is no longer just, reasonable, and not unduly discriminatory. The rights and obligations of a rollover customer should bear a rational relationship to the planning and construction obligations imposed on the transmission provider by the rollover rights. We find, for the reasons explained below, that the current policy no longer meets this standard and that a five-year term will ensure greater consistency between the rights and obligations of customers and

⁷⁴⁸ See also Morgan Stanley.

the corresponding planning and construction obligations of transmission providers. We also believe that an increase to a five-year term is consistent with the native load protections contained in new section 217 of the FPA, primarily because requiring longer-term agreements ensures that the rollover right is used by transmission customers with long-term obligations to purchase capacity.⁷⁴⁹ Accordingly, the Commission adopts a five-year minimum contract term in order for a customer to be eligible for a rollover right. At the end of its initial five-year contract term, a transmission customer must, within the one-year notice period (discussed more fully below), agree to another five-year contract term or match any longer-term competing request in order to be eligible for a subsequent rollover.

1232. Our decision to adopt a five-year minimum term will remedy many of the problems associated with the current policy. Under our current policy, a customer can secure transmission service for one year and, in so doing, require the transmission provider to plan and upgrade its system on the assumption the rollover right will be continually renewed. For example, if a transmission provider's planning horizon is 10 years, a one-year reservation would require the transmission provider to plan and upgrade

⁷⁴⁹ See EPAAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q), which provides that "[t]he Commission shall exercise the authority of the Commission under [the FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long term basis for long term power supply arrangements made, or planned, to meet such needs."

the system as if the customer had purchased 10 years' service (i.e., would exercise its rollover right every year during that 10-year period). Because of this, the customer receives a guarantee of service beyond what it has contracted to pay for and the transmission provider must plan for service that may not actually be used.

1233. By failing to link the customer's rights and obligations with those of the transmission provider, the current policy can have several detrimental effects. For example, it requires the transmission provider to plan and construct facilities that may not be necessary to serve load. Given the difficulty of siting new transmission, it is inappropriate to require transmission providers to use finite resources to finance and construct facilities that may not be necessary. Additionally, the current policy harms OATT customers by allowing rollover customers to tie up capacity that may be needed by other customers. This is because the current policy allows a rollover customer to lock up existing capacity, regardless of whether the rollover customer intends to use that capacity. This reduces the availability of existing capacity for other customers and, in turn, reduces competitive alternatives for customers.

1234. Some commenters have argued that the Commission should use a shorter period, such as three years, that is more aligned with auctions in retail access markets or existing commercial practices. We disagree. The purpose of our reform of the rollover rights policy is to ensure that the rights and obligations of the customer are better aligned with the planning and construction obligations of the transmission provider. It is not to link the term of the rollover right to any particular commercial practice in any particular

region. We do not believe that such a policy could be fairly implemented in any event. Commercial practices vary between the regions and change over time, and it would therefore be impractical to tailor the rollover rights in the OATT to the varying commercial practices across the country.

1235. We also do not believe that adopting a five-year minimum term will have an adverse effect on participation in retail auctions that use three-year solicitations. At the outset, we note that retail auctions use solicitations of varying length and, hence, the fact that some states may use three-year auctions does not provide a basis to establish a generic standard for rollover rights under the OATT. Some states use shorter term auctions (e.g., one year) and, as indicated, we cannot reasonably tailor an OATT rollover obligation to the varying commercial practices across the country. We also do not believe that our policy will have an adverse effect on any such auctions. The winners in a retail solicitation are determined anew in each auction, based on the bids submitted in that auction. A prospective bidder therefore does not need a "rollover right" to compete in an auction. It only needs transmission service over the term of the solicitation (e.g., three years). The fact that it may not have an automatic right to transmission capacity in the next auction simply places it on the same footing as any other bidder.

1236. In response to those commenters who argue that transmission customers making this long-term commitment must also be permitted to change their designated resources and receipt points as their power supply needs change, we believe that such an approach is unworkable. Allowing rollover customers to change their designated resources and

receipt points in this manner would inappropriately result in rollover customers having priority over other transmission customers in the queue that may have already requested service over a given transmission path. This could result in substantial disruptions to transmission service to higher-queued customers requesting long-term service over these paths.⁷⁵⁰ Moreover, transmission customers are not currently guaranteed the ability to turn to other suppliers at other designated resources and receipt points and, therefore, we do not understand how simply increasing the minimum contract term to five years should necessarily result in allowing transmission customers this increased flexibility. Likewise, we do not understand why an increase in the minimum contract term should result, as argued by APPA, TAPS, and others, in a transmission customer not having to compete with other transmission customers for firm capacity whenever its contract comes up for renewal. As discussed below, we will continue to require transmission customers to match competing requests for service as to term and rate, ensuring that transmission customers that value the service the most receive it.

1237. We reject TAPS' proposal to exempt all small customers from the five-year minimum, since this would interfere with transmission providers' ability to plan their systems to meet their customers' needs. As EEI points out, the aggregated loads of

⁷⁵⁰ We agree with EEI that requiring transmission providers to ensure rollover customers the ability to change their designated resources and receipt points without disrupting service to other customers would, taken to its logical conclusion, require transmission providers to construct the transmission system with sufficient redundancy to permit any customer to take service from any resource.

several small customers can have a substantial impact on the system. We therefore believe it would be inappropriate to categorically exempt small customers. We also reject TAPS' proposal to exempt all full and near-full requirements customers, because it would force transmission providers to provide preferential service to certain groups of customers. Additionally, we reject TAPS' proposal to allow customers to exercise rollover rights with only one-year contracts if there is no competing request. Without a competing request, a rollover right is not necessary in order to continue service as long as capacity remains available. Additionally, allowing a rollover for a one-year contract would continue to impose planning and construction obligations on the transmission provider that bear no reasonable relation to the rights and obligations of the rollover rights customer. We further reject TDU Systems' proposal that transmission providers demonstrate the availability of long-term supplies before moving to a five-year term. To do so would effectively require transmission providers to engage in the business of procuring supplies for their transmission customers, which is clearly outside the scope of their obligation to provide transmission service, and could implicate Standards of Conduct issues.

1238. We also reject the proposal of EPSA and others that all currently effective one-year power supply contracts be grandfathered because this would disrupt transmission planning. For example, such an approach would require that a large portion of existing capacity be planned for on a significantly different timeline than that subject to the reformed rollover right. This also would detract from one of the primary goals of

rollover reform, which is to improve transmission planning and encourage longer-term contracting. As discussed below, existing transmission contracts will be permitted to roll over under their existing terms until the first such rollover opportunity following the effectiveness of the reforms required by this Final Rule.

1239. Lastly, we note that many of the reforms adopted elsewhere in this Final Rule will be beneficial to customers that no longer receive rollover rights, as well as to customers with rollover rights that wish to use their rollover rights to turn to alternative suppliers using different transmission paths. First, greater consistency and transparency in ATC calculations will provide greater assurance of nondiscriminatory access to existing transmission capacity. Second, our reforms relating to conditional firm and redispatch service will help to maximize the use of existing capacity, consistent with reliability, thereby providing customers without rollover rights greater flexibility to purchase existing transmission capacity. Third, our clarifications regarding our policy on redirects should improve the ability of transmission customers to redirect their service to new receipt or delivery points. Fourth, lifting the price cap on reassigned transmission capacity should assist transmission customers in reassigning any capacity that may not be needed on a given path because of a change in suppliers that requires service over new transmission paths. This will also necessarily result in the unneeded capacity being freed up for use by other transmission customers, thereby further assisting them in obtaining capacity that they need to access alternative suppliers. Lastly, and most importantly, greater openness and coordination in transmission planning should provide all customers

better information regarding future resource options and access to competitive alternatives. We also believe that improved transmission planning should help to address allegations made by certain transmission customers (e.g., Williams) that even though they have signed up for ten years of service, they have not seen their needs planned for adequately.

b. One-Year Notice Provision

Comments

1240. Many commenters support an increase in the notice period to one year or some other greater time period.⁷⁵¹ Most support the increase based on the argument that the current 60-day notice period makes it very difficult to plan the system, because transmission providers often do not know until 60 days before the end of a contract whether a transmission customer will roll over its service, resulting in potential overbuilding of the system (e.g., because a transmission provider must plan its system assuming a transmission customer will roll over but sometimes it does not). They also argue that it is difficult to re-market capacity in only 60 days if rollover is not sought and

⁷⁵¹ E.g., Ameren, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, East Texas Cooperatives, EEL, E.ON, Entegra, Entergy, FirstEnergy, Great Northern, Imperial, LDWP, LPPC, MidAmerican, MISO, MISO Transmission Owners, Nevada Commission, Nevada Companies, North Carolina Commission Reply, NorthWestern, Northwest IOUs, NRECA, PGP, Pinnacle, PNM-TNMP, Progress Energy, Public Power Council, Salt River, Santa Clara, Southern, South Carolina E&G, SPP, Tacoma, TranServ, TVA, Utah Municipals, and Xcel. Both APPA and TAPS support a one-year notice provision, but only on the condition that the clarifications and modifications they suggest are made.

that potential transmission customers are often unnecessarily turned away because transmission providers are unaware of the availability of capacity until 60 days before the end of a contract subject to a rollover right. In general, these commenters view a one-year notice period as an improvement. However, many of these same commenters do not believe one-year notice is appropriate if the transmission provider must construct facilities to accommodate a rollover and, therefore, the notice should instead be tied to the start date for any necessary upgrades.⁷⁵²

1241. EEI, for example, believes that notice should be tied to the start date of any necessary transmission upgrades, because the transmission provider may be left with stranded transmission capacity if it must begin construction on upgrades necessary to accommodate a rollover before the transmission customer has even indicated whether it will in fact seek a rollover. EEI also argues that a competing customer could be required to pay an incremental rate for network upgrades that could have been avoided if the rollover customer had provided earlier notice of its intention not to seek a rollover. EEI further contends that some state commissions will not allow upgrades where there is only the potential for a rollover. Finally, EEI states that a one-year notice period does not ensure that the transmission provider will be able to re-market the capacity, forcing other transmission customers to bear the increased costs associated with the newly constructed

⁷⁵² E.g., Barrick Reply, Duke, EEI, Entergy, Indianapolis Power Reply, LPPC, Nevada Commission, Nevada Companies, Pinnacle, Progress Energy, South Carolina E&G Reply, Southern, and TVA.

contract. Commenters have not offered sufficient justification for further clarifications to our rollover policies or amendments to section 2.2 at this time.

e. Effectiveness Upon Acceptance of Coordinated and Regional Planning Process and Transition

Comments

1261. Several transmission customers and other commenters support a linkage between rollover reform and planning, but do not support making rollover reforms effective upon acceptance of a transmission provider's coordinated and regional planning process, but rather on successful implementation of that process.⁷⁶⁷ While both TAPS and TDU Systems support the link to planning generally, TAPS goes further and advocates holding transmission providers accountable for failing to plan and construct facilities needed to meet transmission customer needs. TDU Systems point out that the linkage to planning does not remedy concerns that the current market does not generally provide for five-year supply contracts.

1262. Some commenters, however, oppose linking the effectiveness of rollover reform to planning, arguing that rollover reform is needed as quickly as possible.⁷⁶⁸ For example, Duke, Progress Energy, and Southern argue that FPA section 217 provides no indication

⁷⁶⁷ E.g., AWEA, Constellation, EPSA, Exelon, PGP, and PPM.

⁷⁶⁸ E.g., Bonneville, Duke, EEI Reply, North Carolina Commission Reply, Northwest IOUs, PNM-TNMP Reply, Progress Energy, Public Power Council, South Carolina E&G Reply, and Southern.

that the native and network load protections inherent in rollover reform should be subject to conditions such as waiting for the Commission to accept a planning process.

Moreover, Duke argues that developing a planning process will be time-consuming and that holding rollover reform hostage to it could motivate stakeholders with contracts shorter than five years to endlessly try to convince the Commission to delay acceptance of a transmission provider's planning process.

1263. Some commenters contend that linking planning and rollover reform will create differences in tariffs, with each transmission provider having a different effective date for rollover reforms.⁷⁶⁹ MISO argues in its reply that the Commission should clarify in the Final Rule that its requirement that the new policy becomes effective upon acceptance of the transmission provider's coordinated and regional planning process is already met in regions where RTOs or ISOs provide service, as they already have Commission-approved regional transmission planning mechanisms in place. Bonneville argues in its reply for a consistent implementation date across all transmission providers so as to avoid another degree of complexity for customers requiring rollover capacity across multiple transmission providers' systems.

1264. As for the transition period proposed in the NOPR, a variety of commenters point out that, depending on the status of any given contract, making the one-year notice provision effective on acceptance of a transmission provider's planning process could

⁷⁶⁹ E.g., Northwest IOUs, Duke Reply and EEI Reply.

leave some transmission customers unable to provide one-year notice if there is less than one year remaining on their contracts.⁷⁷⁰ FirstEnergy, Exelon, Great Northern, and TAPS emphasize that existing transmission customers should be permitted one more rollover under the current rules, because the parties to such agreements have relied on the current rules in meeting their transmission needs. APPA and TAPS point out that transmission customers will need a sufficient amount of time to secure five-year power agreements to meet the new requirements. AWEA argues generally for a transition period during which existing customers can maintain or relinquish their existing rollover rights under current rules and become subject to new requirements only at the end of the transition period.

Commission Determination

1265. The Commission adopts the NOPR proposal to make rollover reform effective at the time of acceptance by the Commission of a transmission provider's coordinated and regional planning process also required by this Final Rule. We believe that rollover reform and transmission planning are closely related, because according to our longstanding policy, transmission service eligible for a rollover right must be set aside for rollover customers and included in transmission planning. We believe that it is necessary that reforms in both areas proceed together, and therefore, we reject the suggestion of some commenters that rollover reform proceed independent of transmission planning reform. We understand that our approach may result in differences in transmission

⁷⁷⁰ E.g., APPA, FirstEnergy, Northwest IOUs, PGP, and Public Power Council.

providers' OATTs, with some having a different effective date for rollover reforms.

However, because the effectiveness of rollover reform will be tied to acceptance of a transmission provider's coordinated and regional transmission planning process, rollover reforms in any given region generally should be effective within the same time period.

1266. We reject the arguments by some commenters that rollover reform be made effective upon the "successful" implementation, as opposed to acceptance by the Commission, of a transmission provider's coordinated and regional planning process. We believe that utilizing a subjective deadline, such as the successful implementation of the planning process, could result in significant confusion in the industry as to when rollover reforms should be effective. Furthermore, an existing filed and accepted transmission planning process, such as those that may be on file for RTOs and ISOs, does not trigger the effectiveness of rollover reform for transmission providers using the process. Such RTOs and ISOs and their transmission-owning members must, as discussed elsewhere in this Final Rule, comply with the planning reforms required by the Final Rule through the compliance filing procedures identified in section IV.C. It is Commission acceptance of these compliance filings that will trigger effectiveness of rollover reform for these transmission providers, assuming rollover reform is applicable to their tariff services in the first instance.

1267. In response to commenters' concerns that, depending on the effective date of rollover reform, certain customers may not have a year or more left on their contracts such that they can comply with the one-year notice provision, we emphasize that existing

contracts with a rollover right at the time of effectiveness of rollover reform may exercise their next rollover based on the existing notice rules. It is only a rollover contract entered into or renewed after the effectiveness of rollover reform that must comply with the new rollover provisions, including the one-year notice requirement.

4. Modification of Receipt or Delivery Points

1268. Section 22 of the pro forma OATT provides that a transmission customer taking firm point-to-point service may modify its receipt and delivery points, i.e., redirect its service, on either a non-firm or a firm basis. Section 22.1 (Modifications on a Non-Firm Basis) provides that, subject to certain conditions, a firm point-to-point customer may request transmission service on a non-firm basis over receipt and delivery points other than those specified in its service agreement (known as secondary receipt and delivery points) in amounts not to exceed its firm capacity reservation, without incurring an additional non-firm point-to-point service charge or executing a new service agreement. Section 22.2 (Modifications on a Firm Basis) provides that any request to modify receipt and delivery points on a firm basis shall be treated as a new request for service in accordance with section 17 of the pro forma OATT (Procedures for Arranging Firm Point-to-Point Transmission Service), except that the transmission customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing service agreement. While such new request is pending, the transmission customer retains its priority for service at the existing firm receipt and delivery points specified in its service agreement.

**ORDONNANCE N° 890-A
DE LA
FEDERAL ENERGY REGULATORY COMMISSION**

B. Coordinated, Open, and Transparent Planning

1. The Need for Reform

153. In Order No. 890, the Commission required transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level. Transmission providers, including RTOs and ISOs, were directed to submit a compliance filing describing their proposals for a coordinated and regional planning process that comply with the planning principles and other requirements of Order No. 890. The transmission planning process must be documented as an attachment to the transmission provider's OATT.

154. The Commission determined that planning-related reforms were necessary in order to limit opportunities for undue discrimination and to ensure that comparable transmission service is provided by all public utility transmission providers. The Commission stated that it did not intend to reopen prior approvals regarding planning processes adopted by RTOs and ISOs and, instead, sought to ensure that such planning processes are consistent with or superior to the requirements of Order No. 890. In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. The Commission therefore directed RTOs and ISOs to indicate in their compliance filings how participating transmission owners within their footprint will comply with the planning requirements of Order No. 890.

155. The Commission also noted that the planning obligations imposed in Order No. 890 did not address or dictate which investments identified in a transmission plan should

possession to enable the transmission provider to calculate the level of congestion costs that is occurring in the near future.⁷⁹ This may necessarily involve customers providing their cost information. As E.ON U.S. notes, transmission providers must maintain the confidentiality of this information, protecting it from distribution to employees of the merchant function and its affiliates. Transmission providers must clearly define in their Attachment K the information sharing obligations placed on customers in the context of economic planning.

207. We clarify in response to Duke that good faith projections of anticipated point-to-point uses of the transmission system are intended only to give the transmission provider additional data to consider in its planning activities. The Commission did not intend to suggest in Order No. 890 that such projections be treated as a proxy for actual reservations. Even though they are not the equivalent of reserved uses of the system, such projections could, for example, provide planners with likely scenarios for new investment.

e. Comparability

208. In order to satisfy the comparability principle, transmission providers must develop, after considering the data and comments supplied by customers and other stakeholders, a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (e.g.,

⁷⁹ See id. at P 550. The Commission also required the transmission provider's merchant function to provide any information necessary for economic planning studies (e.g., redispatch cost information).

Commission Determination

213. Comparability requires that the interests of transmission providers and their similarly-situated customers be treated on a comparable basis in the transmission planning process.⁸⁰ We do not believe that this creates a conflict with least cost planning at the state level. Comparability simply requires that a transmission provider engage in comparable planning for its similarly-situated customers. The transmission provider retains discretion as to which solutions to pursue. Transmission providers are therefore not required to include all customer-identified projects in its plan, so long as similarly-situated customers are given comparable consideration.

214. With regard to non-public utility transmission providers, we reiterate our expectation of participation in the planning processes established pursuant to Order No. 890 consistent with their reciprocity obligations.⁸¹ 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 providers. A non-public utility transmission provider with reciprocity obligations that declines to adopt a planning process that complies with Order No. 890 therefore may not be considered to be providing reciprocal transmission service and may be at risk of being denied open access transmission services by a public utility transmission provider. We will consider on a case-by-case basis how a transmission provider should treat for planning purposes a non-

⁸⁰ See id. at P 494.

⁸¹ See id. at P 441.

planning process, each transmission provider is required to identify how it will treat resources on a comparable basis and, therefore, should identify how it will determine comparability for purposes of transmission planning.

f. Dispute Resolution

217. In order to satisfy the dispute resolution principle, transmission providers must develop a dispute resolution process to manage disputes that arise from the Attachment K planning process. The Commission stated that the dispute resolution process must address both procedural and substantive planning issues, as the purpose for including a dispute resolution process is to provide a means for parties to resolve all disputes related to the planning process before turning to the Commission.

Requests for Rehearing and Clarification

218. TDU Systems ask the Commission to clarify that transmission providers must develop a dispute resolution process in collaboration with transmission customers and other stakeholders. TDU Systems argue that this clarification is necessary to assure that “the shape of the table” for dispute resolution is not fashioned to favor one side.

219. Duke asks the Commission to clarify whether alternative dispute resolution (ADR) will become a vehicle to challenge the transmission plan ultimately adopted by the transmission provider. Duke questions any intent by the Commission to exercise authority to approve or disapprove a transmission plan. Duke argues that ADR should not be used to substantively second guess a vertically-integrated transmission provider’s plan. If ADR is intended to address substantive planning issues, Duke asks the Commission to clearly delineate the scope of those issues. Duke also asks the

and others have been able to secure dynamic scheduling agreements on a negotiated basis, and we do not intend to disrupt those agreements in this proceeding.

2. Rollover Rights

632. In Order No. 890, the Commission revised the rollover provision in section 2.2 of the pro forma OATT, which grants an ongoing right to firm transmission customers to renew or “rollover” their contracts. Under Order No. 888, transmission customers were allowed to rollover contracts with a minimum term of one year, provided that they provide notification of the rollover no later than 60 days prior to expiration of their service agreements. The Commission concluded that this provision was no longer just and reasonable, extending the minimum term necessary to qualify for a rollover to five years and the notice deadline to one year. Thus, a transmission customer must agree to another five-year contract term or match any longer term competing request within one year of expiration of its five-year service agreement in order to be eligible for a subsequent rollover. The Commission stated that this reform will become effective for each transmission provider upon acceptance of the transmission provider’s compliance filing containing a coordinated and regional planning process that satisfies the requirements of Order No. 890.

633. The Commission declined to eliminate the requirement that an existing transmission customer match competing offers as to term and rate in order to roll over its service. The Commission also continued to require rollover restrictions to be based only on reasonable forecasts of native load growth or preexisting contracts that commence in

customers and the transmission provider serving native load except in the limited circumstance when it would require the shedding of bundled retail load.²⁶⁹ Nothing in our changes to rollover policies justifies modifying that requirement. We also decline to determine generically the weight to be given to state-approved integrated resource plans in the determination of reasonable native load restrictions. The determinative factors in each case will be identified based on the record, along with the relevant particular supporting documentation to be considered.

e. **Effectiveness Upon Acceptance of Coordinated and Regional Planning Process**

Requests for Rehearing and Clarification

681. Duke argues that the rollover reforms should be implemented immediately and not upon acceptance of the transmission provider's planning process compliance filing.

Duke contends that the Commission unambiguously found that the prior rollover policy was no longer just and reasonable and not unduly discriminatory. Duke also argues that the prior rollover policy is inconsistent with FPA section 217, suggesting that the prior policy conflicts with the reasonable needs of LSEs to satisfy their service obligations.

Duke therefore argues that it is not reasonable for the Commission to allow its prior rollover policies to remain in place pending acceptance of the transmission planning process compliance filings. Duke contends that the Commission did not base its finding that rollover policies were in need of reform on the lack of transmission planning

²⁶⁹ See Northern States Power Co., 89 FERC ¶ 61,178 (1999).

processes and, therefore, making one conditioned on the other is unsupported.

682. TAPS requests clarification of the timing of compliance filings implementing the new rollover policies. TAPS questions whether transmission providers were required to submit conforming changes to section 2.2 in their initial compliance filings or as part of the Attachment K compliance filings due at a later date. If the former, TAPS states that transmission providers would be deleting the current language that will still be in effect. TAPS suggests that changes to section 2.2 not be made until the Attachment K is accepted.

Commission Determination

683. The Commission denies rehearing of the determination to tie the effectiveness of rollover reform to the acceptance of the transmission provider's coordinated and regional planning process required under Order No. 890. As the Commission explained in Order No. 890, reforms regarding rollovers and transmission planning must proceed together because they are closely related. Under our longstanding policy, transmission service eligible for a rollover right must be set aside for rollover customers and included in transmission planning. Duke is therefore incorrect in suggesting that the Commission did not rely on our planning-related reforms when fashioning a remedy to ensure rollover policies remain just and reasonable and not unduly discriminatory.

684. With regard to TAPS' concern regarding the timing of compliance filings implementing the new rollover policies, we reiterate that the previously existing rollover provisions will remain in effect for the transmission provider until such time as the Commission accepts the transmission provider's Attachment K compliance filing.

Accordingly, it is only after a transmission provider's Attachment K planning process is accepted by the Commission that the transmission provider should file the rollover reform language, and the effective date of that language should be commensurate with the date of that filing. We have revised section 2.2 of the pro forma OATT to make this clear.

f. Transition Issues

Requests for Rehearing and Clarification

685. Great Northern seeks clarification, or in the alternative rehearing, regarding how rollover reform would apply to transmission service requests that were made before the issuance of Order No. 890 in reliance on the prior version of section 2.2 of the pro forma OATT. If Order No. 890 is implemented in such a way as to require a minimum five-year contract term in order for rollover rights to attach to pending transmission service requests, Great Northern contends it would cause significant disruption in the development and financing of competitive generation projects already in the queue. Great Northern suggests that requiring pending projects to submit new contracts for five-year terms in order to obtain rollover rights in turn would require it to restart its project planning process for each of those projects.

686. Great Northern therefore asks the Commission to confirm that the current one-year contract commitment right of first refusal rule will continue to apply to transmission service requests that were made prior to the issuance of Order No. 890 and that the five-year contract commitment right of first refusal rule will not apply until the first rollover date after both the executed transmission service contract and revised section 2.2 of the

**ORDONNANCE N° 890-B
DE LA
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6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a

transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

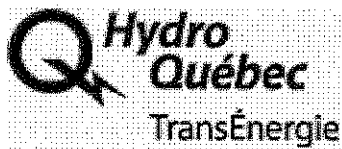
7.1 Billing Procedure:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

(Name of Transmission Provider)

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- (vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and
- (viii) The relevant cost allocation procedures or principles.



TARIFS ET CONDITIONS DES SERVICES DE TRANSPORT D'HYDRO-QUÉBEC

entend mettre fin à tous les contrats de service de transport liant les parties. Le Transporteur doit alors calculer toutes les sommes qui lui sont dues, incluant le remboursement des ajouts au réseau assumés par le Transporteur et les intérêts sur les sommes impayées calculés conformément à l'article 7.2 et aviser le client du service de transport du montant net alors dû.

12 Procédures de traitement des plaintes

12.1 Procédure applicable : Toute plainte d'un client du service de transport concernant l'application d'un tarif ou d'une condition de transport doit être traitée conformément aux dispositions pertinentes de la procédure d'examen des plaintes approuvée par la Régie conformément à la Loi. Le Distributeur agira au nom des clients de charge locale pour toute plainte concernant la Partie IV des présentes.

12.2 Recours aux tribunaux compétents : Tout différend qui ne relève pas de la compétence exclusive de la Régie doit être soumis aux tribunaux compétents.

12A Raccordement de centrales au réseau de transport et de distribution

12A.1 Entente de raccordement : Suite à toute demande de raccordement de centrale d'un client admissible, la signature d'une Entente de raccordement substantiellement équivalente à l'Entente-type disponible sur le site Internet du Transporteur est

requis préalablement à tout raccordement de centrale au réseau de transport ou au réseau de distribution et visant à répondre aux besoins des clients du service de transport en vertu de la Partie II, de la Partie III et de la Partie IV des présentes. Pour toute centrale existante, à moins que des dispositions différentes ne soient convenues par écrit avec le propriétaire de celle-ci, les dispositions prévues à l'Entente-type de raccordement s'appliquent. Le propriétaire de la centrale doit respecter les exigences techniques du Transporteur relatives au raccordement des centrales, ainsi que les limites d'émissions de perturbations autorisées sur le réseau de transport et de distribution.

La signature de l'Entente de raccordement ne constitue pas une réservation de service de transport en vertu des présentes et le dépôt prévu à l'article 17.3 n'est pas requis pour la demande de raccordement de centrale.

12A.2 Achat de services point à point ou remboursement :

Lors de la signature de l'Entente de raccordement, les dispositions pour le raccordement de la centrale au réseau prévues aux présentes, notamment celles décrites à l'appendice J, s'appliquent. De plus, le propriétaire de la centrale ou un tiers désigné à cette fin par celui-ci doit, à la satisfaction du Transporteur, prendre au moins un des engagements suivants:

i) Convention de service de transport de long terme:

Au moins une convention de service doit avoir été signée pour le service de transport ferme à long terme. La valeur actualisée des paiements à verser au Transporteur pendant la durée des conventions de service applicables est au moins égale aux coûts encourus par le Transporteur pour assurer le raccordement de la centrale, moins tout montant remboursé au Transporteur;

ii) Engagement d'achat de services de transport:

Un engagement d'achat de services de transport ferme ou non ferme de point à point de type "take or pay" doit être signé pour un montant au moins égal en valeur actualisée aux coûts encourus par le Transporteur, moins tout montant remboursé au Transporteur, pour assurer le raccordement de la centrale.

Sous réserve du paragraphe suivant, à la fin de chaque période de douze (12) mois suivant le 31 décembre de l'année de mise en service de la centrale, le montant annuel de l'engagement d'achat (valeur A) est soustrait du produit de la production annuelle injectée sur le réseau mesurée au point de raccordement et du tarif du service de point à point contracté et, à défaut, du service horaire non ferme (valeur B). Tout écart négatif

entre les deux (2) valeurs annuelles (B - A) est payé au Transporteur à la fin de l'année où l'écart négatif est constaté. Le montant à payer par le client doit être réduit de l'écart cumulatif (B-A) des années antérieures si ce dernier est positif; si cet écart cumulatif (B-A) des années antérieures est plus élevé que le montant à payer, le montant net à payer s'établit à zéro et le solde de l'écart cumulatif (B-A) est disponible pour les années subséquentes. Si l'écart entre les deux (2) valeurs annuelles (B-A) est positif et que l'écart cumulatif (B-A) des années antérieures est négatif, un remboursement est effectué par le Transporteur au client. Ce remboursement est égal au moindre de l'écart positif entre les valeurs annuelles (B-A) et de l'écart cumulatif (B-A) des années antérieures en valeur absolue.

Pendant l'année de mise en service de la centrale, l'engagement annuel d'achat est établi au pro-rata du nombre de jours entre la date de mise en service de la centrale et le 31 décembre de l'année de mise en service.

L'engagement annuel d'achat, soit la valeur A indiquée ci-dessus, représente une annuité calculée à partir des paramètres suivants: a) coûts encourus par le Transporteur pour assurer le

raccordement de la centrale, majoré d'un montant de 15% pour couvrir les frais d'entretien et d'exploitation sur vingt (20) ans, lorsque ceux-ci sont encourus par le Transporteur et, majoré des taxes applicables, moins tout montant remboursé par le client; b) coût en capital prospectif du Transporteur approuvé par la Régie et c) durée de l'engagement d'achat; et

iii) Remboursement:

Un montant égal en valeur actualisée aux coûts encourus par le Transporteur pour assurer le raccordement de la centrale doit être remboursé au Transporteur.

Le propriétaire de la centrale n'est tenu de fournir aucun des engagements indiqués ci-dessus pour toute production retenue par le Distributeur lors d'un appel d'offres ou en vertu d'une dispense d'appel d'offres, et que le Distributeur a désigné conformément à l'article 38 des présentes. Lorsqu'une partie uniquement d'une centrale est retenue par le Distributeur, l'engagement du propriétaire de la centrale, ou du tiers qu'il a désigné à cette fin, doit couvrir un montant égal aux coûts assumés par le Transporteur pour assurer le raccordement de la centrale, multipliés par le facteur suivant: le nombre un (1), moins le rapport entre la puissance en kilowatts (kW) retenue par le Distributeur et la

puissance nominale totale en kW des groupes turbine-alternateurs de la centrale. En cas d'abandon avant la mise en service de la centrale, le demandeur doit rembourser la totalité des coûts encourus par le Transporteur.

12A.3 Séquence des études d'impact : À moins d'une mention à l'effet contraire, les dispositions prévues aux articles 19, 20 et 21 des présentes s'appliquent, mutatis mutandis, à toute demande de raccordement de centrale. Le Transporteur affiche sur son site OASIS la date du dépôt auprès du Transporteur d'une demande complète comprenant les informations indiquées à l'article 17.2, ainsi que les données techniques nécessaires à la réalisation de l'étude d'impact. Pour maintenir sa position dans la séquence des études d'impact et, par la suite, dans celle des projets en cours, le demandeur doit respecter les délais indiqués aux articles 19.1 à 19.8 pour toutes les étapes qui y sont prévues et prendre l'un des engagements indiqués à l'article 12A.2.

Suite à toute demande du Distributeur pour le raccordement de centrales dans le cadre d'un appel d'offres, la puissance nécessaire à la réalisation des projets de l'appel d'offres du Distributeur est inscrite dans la séquence des études d'impact et, par la suite, chacun des projets de centrales retenus par le Distributeur est maintenu dans la séquence. Toute

puissance inscrite dans la séquence des études d'impact dans le cadre d'un appel d'offres du Distributeur est libérée au fur et à mesure que celle-ci n'est plus requise pour les besoins du Distributeur.

Suite à une modification substantielle du projet ayant fait l'objet d'une demande d'étude d'impact, notamment quant à la localisation, à la puissance maximale à transporter et aux caractéristiques des équipements de production, celui-ci sera traité comme une nouvelle demande et se verra attribuer une place dans la séquence des études d'impact correspondant à la date du dépôt auprès du Transporteur de la demande complète visant le projet modifié. Toute modification substantielle à la centrale après la mise en service de celle-ci doit faire l'objet d'une demande d'étude d'impact auprès du Transporteur conformément aux présentes.

12A.4 Droit de maintien : La demande de raccordement de centrale du client admissible est réputée résiliée et retirée à l'expiration du délai maximal de trois cent soixante-cinq (365) jours indiqué à l'article 19.3 ou du délai maximal de cent quatre-vingts (180) jours indiqué à l'article 19.4.

Nonobstant le paragraphe précédent, dans les trente (30) jours suivant l'expiration des délais pré-cités, le client peut demeurer en attente s'il avise par écrit le Transporteur de son intention de maintenir son

projet dans la séquence des projets en cours.

Advenant le cas où le Transporteur reçoive, subséquemment au dépôt de la demande de raccordement de centrale du client en vertu de l'article 12A.1, toute autre demande complète d'un client admissible dont le service demandé peut requérir, de l'avis du Transporteur, des ajouts au réseau complémentaires ou concurrentiels à ceux qui étaient prévus pour le client dont le projet est en attente, alors ce dernier bénéficiera, suite à la réception d'un avis écrit du Transporteur à cet effet, d'un nouveau délai de quarante-cinq (45) jours pour confirmer par écrit au Transporteur qu'il accepte de fournir l'un des engagements prévus à l'article 12A pour la réalisation de son projet, afin de maintenir sa position dans la séquence des projets en cours. Dans ce cas, l'engagement pris par le client demeure en toutes circonstances. En cas d'abandon, les dispositions prévues aux présentes s'appliquent.

Dans le cas contraire, une fois ce nouveau délai de quarante-cinq (45) jours expiré, sa demande de service cesse d'être une demande complète et est résiliée et retirée définitivement.

Toutefois, si le client ne peut respecter les délais pré-cités de trois cent soixante-cinq (365) ou de cent quatre-vingts (180) jours en raison de délais dus à la délivrance d'une autorisation gouvernementale

nécessaire à la réalisation de son projet et si le client a démontré par écrit au Transporteur avoir effectué toutes les démarches raisonnablement nécessaires à l'obtention d'une telle autorisation et qu'il ne fournit pas l'un des engagements prévus à l'article 12A pour la réalisation de son projet, le projet maintient sa position dans la séquence des projets en cours et seuls les projets nécessitant des ajouts au réseau complémentaires ou concurrentiels et ayant une date de mise en service antérieure à celui-ci le devanceront.

Dans le dernier cas mentionné au paragraphe ci-dessus, le client dispose d'un délai additionnel de trente (30) jours après la réception d'une telle autorisation gouvernementale pour confirmer par écrit au Transporteur qu'il accepte de signer une entente de raccordement concernant son projet et fournir l'un des engagements prévus au présent article. Dans le cas contraire, une fois ce nouveau délai de trente (30) jours expiré, sa demande de service cesse d'être une demande complète et est résiliée et retirée définitivement.

12A.5 Étude exploratoire : Préalablement à une demande de raccordement de centrale, le client peut, afin d'obtenir un ordre de grandeur concernant la faisabilité du raccordement de son projet de centrale, adresser au Transporteur une demande écrite d'étude

exploratoire en vertu du présent article 12A.5. L'objectif de l'étude exploratoire est de fournir une estimation paramétrique approximative d'un seul scénario de raccordement possible pour la centrale faisant l'objet de la demande. Le Transporteur s'efforcera, dans la mesure du possible, de répondre à une telle demande dans un délai maximal de six (6) semaines suivant la réception de la demande écrite du client, en transmettant au demandeur un rapport sommaire présentant un scénario approximatif du coût et du délai pour réaliser les travaux d'intégration de la centrale au réseau du Transporteur.

La demande d'étude exploratoire doit être transmise par écrit au Transporteur accompagnée des informations techniques nécessaires pour réaliser l'étude exploratoire et du paiement complet de celle-ci, au montant non remboursable de 5 000,00\$, plus les taxes applicables. Ce montant représente la totalité des coûts facturés par le Transporteur pour réaliser l'étude exploratoire. Tout scénario additionnel demandé par le client constitue une demande distincte d'étude exploratoire et les modalités décrites ci-dessus s'appliquent à celle-ci.

L'étude exploratoire ne constitue ni une demande d'étude d'impact, ni une demande de raccordement de centrale, ni une demande de réservation de transport et elle ne comporte aucun engagement de la part du

Transporteur quant à la précision ou l'exactitude des informations qui seront remises au demandeur en réponse à cette demande. Les dispositions prévues aux articles 12A.1 à 12A.4 ci-dessus ne s'appliquent pas à une demande d'étude exploratoire.

12A.6 Clauses communes: Les dispositions prévues à la Partie I des présentes s'appliquent, mutatis mutandis, au propriétaire de la centrale, ou au tiers qu'il a désigné, le cas échéant.

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un système commun de régulation automatique de la production afin :

- (1) de faire correspondre, en tout temps, la puissance produite par les groupes turbine-alternateurs dans le(s) réseau(x) d'électricité et la puissance et l'énergie achetées auprès d'entités situées à l'extérieur du(des) réseau(x) d'électricité, avec la charge dans le(s) réseau(x) d'électricité;
- (2) de maintenir les échanges programmés avec les autres zones de réglage, dans les limites des pratiques usuelles des services publics;
- (3) de maintenir la fréquence du(des) réseau(x) d'électricité dans des limites raisonnables, conformément aux pratiques usuelles des services publics; et
- (4) de fournir une capacité de production suffisante pour maintenir des réserves d'exploitation, conformément aux pratiques usuelles des services publics.

2 Procédures d'attribution initiale et de renouvellement

2.1 Abrogé

2.2 Priorité de réservation pour les clients existants du service ferme : Les clients existants du service de transport ferme avec une durée de contrat ~~d'un~~de cinq ans ou plus sont en droit de continuer d'utiliser le service de transport du Transporteur à l'expiration, à la reconduction ou au renouvellement de leur contrat.

Cette priorité de réservation de transport ne dépend pas du fait que le client existant continue à acheter l'électricité du Producteur, ou choisit d'acheter l'électricité d'un autre fournisseur. Si, à la fin de la durée du contrat, le réseau de transport du Transporteur ne peut pas répondre à toutes les demandes de service de transport, le client existant de service ferme doit accepter une durée de contrat au moins égale à ~~celle-la~~ la durée de contrat plus longue d'une nouvelle demande concurrente de la part d'un nouveau client admissible et accepter de payer le tarif juste et raisonnable courant approuvé par la Régie pour ce service; ce droit du client existant (ci-après le droit de préemption) est conditionnel à ce que le nouveau contrat ait à condition que le client du service ferme détienne un droit de préemption à la fin de la durée de ce service seulement si le nouveau contrat a une durée de cinq ans ou plus. Le client existant du service ferme doit faire savoir au Transporteur s'il exercera son droit de préemption au moins un an avant la date d'expiration de sa convention de service de transport. Cette priorité de réservation de transport pour les clients existants du service ferme est un droit qui se continue et qui peut être exercé à la fin de tous les contrats fermes ~~d'un~~ ande cinq ans ou plus. À moins qu'elles n'aient été révoquées, Les conventions de service bénéficiantassujetties à d'un droit de

préemption qui ont été conclues avant la date établie à l'article 44.2 ou qui sont associées à une demande de service de transport reçue avant la date établie à l'article 44.2, à moins qu'elles ne soient révoquées, (ci-après les conventions de service en cours) dont le terme expire dans les cinq ans suivant cette date deviendront assujetties aux exigences relatives à la durée de cinq ans et au préavis d'un an à la date de leur première reconduction, à la condition que le client existant ait fait savoir au Transporteur qu'il exercera son droit de préemption au moins 60 jours avant l'expiration de ce terme. À moins qu'elles n'aient été révoquées, les conventions de service en cours dont le terme expire plus de cinq ans suivant la date établie à l'article 44.2 seront assujetties à l'exigence relative à la durée de cinq ans et au préavis d'un an. l'avis d'un an s'applique aux conventions de service ayant encore une durée de contrat de cinq ans ou plus à la date établie à l'article 44.2. à condition que le client en avise le Transporteur par écrit et via OASIS au plus tard soixante (60) jours avant la fin du contrat.

3 Services complémentaires

Le Transporteur est tenu de fournir, et le client du service de transport est tenu d'acheter, les services complémentaires suivants : (i) gestion du réseau et (ii) réglage de tension.

**MISE À JOUR DE LA PROPOSITION DE
MODIFICATIONS AUX
TARIFS ET CONDITIONS DES SERVICES DE
TRANSPORT D'HYDRO-QUÉBEC
À LA SUITE DE L'ORDONNANCE N° 890 DE LA FERC**

3.3 Processus de planification des installations de transport

1 *Aperçu de l'ordonnance n° 890*

2 D'après la FERC, l'ordonnance n° 888 et l'OATT *pro forma* qui en découle ne
3 constituent pas une protection suffisante contre la discrimination induite en
4 matière de planification des réseaux de transport¹⁶. L'organisme souligne
5 également, depuis la publication de cette dernière ordonnance, le déclin de
6 l'investissement en transport aux États-Unis par rapport à la croissance de
7 la charge¹⁷.

8 Pour assurer que tous les transporteurs, y compris les organisations de
9 transport régionales et les gestionnaires indépendants de réseaux, offrent un
10 service de transport véritablement comparable, l'ordonnance n° 890 leur
11 impose les obligations suivantes :

- 12 - participer à un processus de planification coordonné et transparent à
13 l'échelle locale et régionale¹⁸;
- 14 - satisfaire neuf principes relatifs à ce processus : la coordination,
15 l'ouverture, la transparence, l'échange de renseignements, le traitement
16 comparable des clients, le règlement des différends, la coordination
17 régionale, les études économiques et la répartition des coûts¹⁹;
- 18 - décrire leur processus de planification dans leur OATT ou tarif, dans un
19 nouvel appendice K joint à celui-ci.

20 *Orientation du Transporteur*

21 Aux États-Unis, la pertinence d'ajouter un processus de planification ouvert et
22 transparent, l'appendice K de l'OATT *pro forma*, vise principalement à

¹⁶ Ordonnance n° 890, paragraphe 84.

¹⁷ Ordonnance n° 890, paragraphe 421.

¹⁸ Ordonnance n° 890, paragraphe 435.

¹⁹ Ordonnance n° 890, paragraphes 437, 444-561.

1 combler la déficience d'investissements en infrastructure de transport²⁰. Il y a
2 aux États-Unis huit zones de fiabilité, constituées de plus de 500 transporteurs
3 synchronisés entre eux dans trois grandes interconnexions et dont une large
4 proportion exploite des marchés en temps réel. Les transporteurs desservent
5 de très nombreux distributeurs, coopératives et autres entités. Cette situation
6 génère par ailleurs, selon la FERC, des occasions de discrimination indues
7 par le biais de la planification. Le partage des responsabilités entre les États,
8 responsables de l'alimentation de la charge locale, et la FERC, responsable
9 des accès aux réseaux de transport, pour répondre aux besoins des clients,
10 rend le contrôle des processus de planification plus difficile en l'absence d'un
11 encadrement plus rigoureux, d'où l'ajout de l'appendice K au tarif *pro forma*.

12 Au Québec, le cadre réglementaire assure un niveau d'investissements qui
13 satisfait la demande et maintient un excellent niveau de fiabilité, tout en
14 assurant un contrôle rigoureux de toute forme de discrimination induite envers
15 les clients du Transporteur. La Régie jouit en effet d'une large compétence à
16 l'égard des installations de transport. Conformément à l'article 73 de la *Loi sur*
17 *la Régie de l'énergie*²¹, le Transporteur doit obtenir l'autorisation de la Régie,
18 entre autres pour construire des immeubles ou des actifs destinés au
19 transport. Tout projet de transport d'un coût de 25 millions et plus est assujéti

²⁰ La FERC motive ainsi son intervention au sujet de l'appendice K dès le paragraphe 3 de son ordonnance n° 890 : « 3. *Second, the Final Rule will increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process. Transmission planning is a critical function under the pro forma OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans are developed. These deficiencies are serious, given the substantial need for new infrastructure in this Nation.*²⁰ *We act today to remedy these deficiencies [...]* », UNITED STATES OF AMERICA 118 FERC ¶ 61,119, FEDERAL ENERGY REGULATORY COMMISSION, 18 CFR Parts 35 and 37, (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890), le 16 février 2007, paragraphe 3.

²¹ L.R.Q., chapitre R-6.01.

1 à un régime particulier d'autorisation²². La Régie encadre de plus la politique
2 d'ajouts au réseau prévue aux *Tarifs et conditions*.

3 Par surcroît, le Transporteur rappelle que la Régie a mis en place deux
4 procédures distinctes d'examen de plaintes, conformément à ses décisions
5 D-2002-95 et D-2003-02. La première vise toute question relative à
6 l'application d'un tarif ou d'une condition de transport d'électricité. La seconde
7 porte sur l'examen accéléré en cas de rejet d'une demande de service de
8 transport. Toutes deux prévoient d'abord une plainte auprès du Transporteur.
9 En cas de désaccord du client avec la décision de ce dernier, le client dispose
10 des recours exprès prévus aux articles 94 à 101 de la *Loi sur la Régie*
11 *de l'énergie*.

12 Dans l'ensemble, ce cadre transparent répond déjà aux besoins de la clientèle
13 et en assure le traitement équitable. Par conséquent, le Transporteur
14 considère qu'il n'y a pas lieu de joindre un processus de planification en
15 appendice K à ses *Tarifs et conditions*.

16 De plus, la *Loi sur Hydro-Québec*²³ impose à Hydro-Québec l'obligation de
17 planifier les besoins de la charge locale. Dans la décision D-2002-95,
18 R-3401-98, 2002-04-30, en page 337, la Régie impose au Transporteur
19 d'ajouter la partie IV aux *Tarifs et conditions*, laquelle régit le service de
20 transport pour alimenter la charge locale. À l'opposé, l'OATT *pro forma* de la
21 FERC ne précise pas les conditions d'alimentation de la charge locale des
22 transporteurs. Au Québec, le Distributeur (HQD) est le seul client du
23 Transporteur pour l'alimentation de la charge locale dans sa zone de fiabilité
24 ou son interconnexion²⁴.

²² *Règlement sur les conditions et les cas requérant une autorisation de la Régie de l'énergie*, D. 970-2001, (2001) 133 G.O. II, 6165 [c. R-6.01, r.2].

²³ L.R.Q., chapitre H-5.

²⁴ « La Régie prend acte de l'affirmation d'Hydro-Québec à l'effet que celle-ci a l'obligation, en vertu de la *Loi sur Hydro-Québec* et de la Loi, de desservir les clients de la charge locale. La Régie est néanmoins d'avis qu'il est justifié et opportun, notamment à des fins de transparence

1 En ce qui concerne la planification des besoins du réseau attribuable au
2 service point à point, les principaux constats sont les suivants :

- 3 • La politique d'ajouts au réseau particulière au Québec et le processus
4 d'approbation sous l'autorité de la Régie favorisent les investissements
5 nécessaires dans le réseau de transport de façon transparente et sans
6 aucune forme de discrimination induue.
- 7 • La file d'attente pour les études d'impacts demandées par les autres
8 clients demeure relativement courte et aucun besoin ne reste insatisfait.
- 9 • Il n'y a pas de retard indu dans la réalisation des études d'impact.
- 10 • L'interconnexion Québec étant asynchrone par rapport aux réseaux de
11 transport voisins, les modifications sur le réseau de transport n'ont pas
12 d'incidence significative sur les réseaux voisins et vice versa. Il en va
13 de même avec les écoulements de puissance (« *loop flow* » et
14 « *parallel flow* ») qui doivent être pris en compte entre les transporteurs
15 partageant un système synchrone. Cela dit, le Transporteur participe
16 aux exercices de coordination avec les réseaux voisins, notamment via
17 le Northeast Power Coordinating Council pour traiter entre autres de
18 fiabilité et des contingences comme la perte d'une interconnexion.

19 Comme le Transporteur l'expose en page 10 de la pièce HQT-10, document 1,
20 de la demande R-3669-2008, la situation au Québec n'a rien de comparable
21 avec celle qui a incité la FERC à exiger des transporteurs sous son autorité à
22 joindre à leurs tarifs un processus de planification.

23 Le Transporteur réitère que le cadre législatif et réglementaire actuel répond
24 adéquatement aux besoins exprimés par la FERC sur ce sujet.

25

et de facilité d'interprétation, d'identifier de façon spécifique aux « Tarifs et conditions » les conditions relatives à la desserte de la charge locale, compte tenu des considérations suivantes (...).», D-2002-95, R-3401-98, 2002 04 30, page 335.

**RÉPONSES DU TRANSPORTEUR
À LA DEMANDE DE RENSEIGNEMENTS NUMÉRO 1
D'ÉNERGIE BROOKFIELD MARKETING INC.
(« EBMI »)**

**PHASE 2 – DEMANDE DU TRANSPORTEUR AFIN DE MODIFIER SES
TARIFS
ET CONDITIONS DES SERVICES DE TRANSPORT**

**PROPOSITION DE MODIFICATIONS AUX TARIFS ET CONDITIONS DES
SERVICES DE TRANSPORT D'HYDRO-QUÉBEC**

PROCESSUS DE PLANIFICATION DES INSTALLATIONS DE TRANSPORT

1. **Références :**
- (i) Ordonnance 890 de la FERC, paragraphes 418 à 602 et ses articles correspondants dans l'OATT
 - (ii) HQT-1, Document 1, pages 13-14
 - (iii) Dossier R-3669-2009, HQD-3, Document 3, p. 22

Préambule :

L'ordonnance 890 de la FERC consacre près de 100 pages de l'ordonnance sur la question du processus de planification des installations de transport. Cette obligation impose au transporteur d'établir un processus de planification des installations de transport qui soit coordonné, ouvert et transparent avec son réseau, ses clients de service point à point et toute autre partie intéressée incluant la coordination avec les systèmes qui lui sont interconnectés.

L'ordonnance prévoit comme l'indique le Transporteur dans sa preuve l'importance de satisfaire à neuf (9) principes bien établis par la FERC à l'égard du processus de planification des installations de transport. La FERC prévoit également l'obligation pour le transporteur de décrire son processus de planification dans le tarif par le biais d'une nouvelle annexe K. Le Transporteur est d'avis que cette nouvelle condition prenant la forme de la nouvelle annexe K de l'OATT « vise principalement à combler la déficience d'investissements en infrastructures de transport. » Il s'agit de l'un des motifs soulevés par le Transporteur pour justifier sa décision de ne pas se soumettre de façon spécifique à cette portion de l'ordonnance et de ne pas joindre aux *Tarifs et conditions* le processus de planification devant faire l'objet de l'annexe K.

Référence (i) :

Au paragraphe 422 de l'ordonnance 890 de la FERC on peut lire :

« 422. We do not believe that the existing pro forma OATT is sufficient in an era of increasing transmission congestion and the need for significant new transmission investment. We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many

transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. »

(Nos soulignés)

Aussi, au paragraphe 423 de l'ordonnance 890 de la FERC on peut lire:

« 423. As the Commission explained in Order No. 888, "[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. »

Demandes :

- 1.1 Veuillez indiquer en quoi les extraits mentionnés ci-haut (paragraphe 422 et 423) ne s'appliquent pas au Transporteur.

R1.1

Tel que déjà mentionné dans la preuve du Transporteur (HQT-1, document 1 aux pages 12 et suivantes), le nouveau processus de planification proposé par la Federal Energy Regulatory Commission des États-Unis (la « FERC ») vise surtout à combler la déficience d'investissement en infrastructure de transport « *in an era of increasing transmission congestion and the need for significant new transmission investment* ». Il n'y a pas de problème croissant de congestion au Québec et les investissements requis sur le réseau du Transporteur se font de façon efficiente pour assurer un bon niveau de service.

Lorsque la Commission mentionne que « *We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner* » elle fait vraisemblablement référence aux intérêts divergents que peuvent avoir une multitude de transporteurs qui opèrent dans la plupart des cas dans un même marché ouvert avec différentes zones de prix.

- 1.2 Comment, de façon spécifique, le Transporteur gère-t-il ce « disincentive to remedy congestion » dont il est fait référence au paragraphe 422 de l'ordonnance de la FERC.

R1.2

En mode d'opération normale, il n'y a pas de congestion sur le réseau du Transporteur. La politique d'ajouts au réseau et le processus de planification actuelle, qui impliquent l'intervention de la Régie, favorisent des investissements sur le réseau de manière à éviter la congestion.

- 1.3 Veuillez indiquer quelles sont les démarches positives effectuées par le Transporteur pour éviter toute forme de discrimination potentielle envers ses clients conformément à ce qui est prévu en matière de planification dans l'ordonnance 890 de la FERC.

R1.3

Le Transporteur traite tous ses clients dans le respect des règles et procédures approuvées par la Régie, laquelle est habilitée à traiter toute plainte éventuelle de discrimination contre le Transporteur. Les conditions d'accès au réseau sont les mêmes pour tous les clients auxquels le Transporteur applique de façon non discriminatoire les *Tarifs et conditions des services de transport d'Hydro-Québec* (les « *Tarifs et conditions* ») approuvés par la Régie. Comme celle-ci n'a constaté aucun cas de discrimination, la présomption applicable au Québec est plutôt que le processus actuel ne présente pas de discrimination.

- 1.4 Outre la compétence de la Régie à l'égard des installations de transport en vertu de l'article 73 de la *Loi sur la Régie de l'énergie* ou le mécanisme d'examen de plaintes, veuillez indiquer si le présent cadre réglementaire prévoit d'autres mécanismes de contrôle de la part de la Régie à l'égard de questions de discrimination potentielle envers les clients du Transporteur?

R1.4

Comme il existe un mécanisme pour le traitement des plaintes, c'est dans ce cadre précis que les plaintes doivent être examinées par la Régie.

Outre ses demandes d'autorisation pour des projets de transport, le Transporteur dépose annuellement à la Régie de l'énergie un rapport annuel qui fait état de l'application du

Code de conduite du transporteur et des plaintes déposées à la Régie de l'énergie. Or, aucun client n'a soulevé un cas de discrimination indue lors de la présentation des demandes d'autorisation de projets de transport. La Régie conserve le droit d'examiner sur demande toute allégation de discrimination indue envers les clients du Transporteur.

- 1.5 Veuillez indiquer quelles seraient les contraintes qui pourraient empêcher le Transporteur (s'il y en a) à respecter les nouveaux principes établis par la FERC en matière de processus de planification des installations de transport.

R1.5

Tel que précisé dans la pièce HQT-1, Document 1, pages 12 et suivantes, le processus actuel est adéquat et adapté au contexte du Québec. Le Transporteur n'a donc pas évalué les contraintes organisationnelles et les impacts économiques de modifier son processus de planification.

- 1.6 Comment le Transporteur peut-il justifier que les conditions de réciprocité requises par la FERC seront maintenues sans l'application de ce nouveau principe avec tous les tenants et aboutissants prévus à l'ordonnance 890 de la FERC?

R1.6

La situation particulière du Québec, qui ne nécessite aucunement l'adoption d'un appendice K pour les motifs déjà exposés dans la pièce HQT-1, Document 1, pages 12 et suivantes, n'affecte pas le respect de l'exigence de réciprocité. L'accès ouvert et non discriminatoire au réseau de transport du Transporteur par les tiers n'est aucunement menacé par l'absence d'un appendice K.

- 1.7 Est-ce que le Transporteur a participé à des rencontres de planification avec les réseaux voisins depuis l'entrée en vigueur de l'ordonnance 890 de la FERC?

R1.7

Oui. Le Transporteur rencontre régulièrement les réseaux voisins pour coordonner l'exploitation et la maintenance d'équipements de transport.

- 1.8 Est-ce que le Transporteur a participé/commenté le processus de planification (incluant l'annexe K) de toute autre entité faisant partie de réseaux voisins?

R1.8

Non.

- 1.9 Pour le cas d'une nouvelle interconnexion avec les réseaux voisins, telle celle actuellement proposée entre le Québec et le New-Hampshire (visée par la demande de service de transport n° 120T), en l'absence d'annexe K, veuillez expliquer comment le Transporteur entend respecter les principes d'ouverture et de transparence et de traitement non-discriminatoire?

R1.9

Tout projet d'interconnexion s'inscrit dans le processus de planification en vigueur et satisfait les critères d'ouverture, de transparence et de traitement non discriminatoire, conformément à la politique d'ajouts au réseau approuvée par la Régie et intégrée aux *Tarifs et conditions*.

- 1.10 Veuillez indiquer si le Producteur fournit au Transporteur ses programmes de production, notamment en identifiant la production prévue de chacune de ses centrales:

R1.10

Cette question relève du coordonnateur de la fiabilité. Le Transporteur ne propose aucun changement à ce sujet dans le cadre de la présente demande.

- 1.11 Si oui, à quelle fréquence et sous quelle forme? Sinon, Pourquoi?

R1.11

Cette question relève du coordonnateur de la fiabilité. Le Transporteur ne propose aucun changement à ce sujet dans le cadre de la présente demande.

Préambule :

En référence toujours aux questions relatives à la planification, nous référons le Transporteur à une demande de renseignements qui a été formulée au Distributeur dans le dossier R-3689-2009.

Référence (iii) :

« 11.3. Quels genres de programmes de prévision des besoins, s'il y a lieu, sont-ils communiqués au Transporteur ainsi qu'au Producteur par le Distributeur. Veuillez aussi indiquer à quelles fréquences ces programmes sont-ils communiqués au Transporteur et/ou au Producteur.

Réponse :

Les prévisions horaires des besoins réguliers du Distributeur sont émises pour un horizon de 12 jours par la Direction Contrôle des mouvements d'Énergie du Transporteur, conformément à son rôle de coordonnateur de la fiabilité au Québec. Cette prévision est transmise au Distributeur et au Producteur. »

- 1.12 Veuillez indiquer si pour les fins d'établir les prévisions horaires, la Direction Contrôle des mouvements d'Énergie du Transporteur obtient des informations du Distributeur

R1.12

Cette question relève du coordonnateur de la fiabilité. Le Transporteur ne propose aucun changement à ce sujet dans le cadre de la présente demande.

- 1.13 Si oui, veuillez préciser la nature de ces informations (sous quelle forme, à quelle fréquence, etc...)

R1.13

Cette question relève du coordonnateur de la fiabilité. Le Transporteur ne propose aucun changement à ce sujet dans le cadre de la présente demande.

- 1.14 Quelles sont les autres informations, le cas échéant, que le Distributeur fournit au Transporteur à l'égard de ses programmes de consommation ou de prévision de la demande?

R1.14

Cette question relève du coordonnateur de la fiabilité. Le Transporteur ne propose aucun changement à ce sujet dans le cadre de la présente demande.

1.15 Pour chaque information, veuillez préciser à quelle fréquence cette information est transmise au Transporteur, sous quelle forme et la nature de l'information transmise?

R1.15

Sans objet.

À l'égard du même sujet et eu égard aux mêmes références, nous ajoutons ci-après les questions soulevées par notre expert monsieur Bill Marshall :

Préambule :

A major new requirement under Order 890 is for the Transmission Provider to establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, 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 non-discriminatory basis. In addition the process is to be provided as an attachment to the Transmission Provider's Tariff (Attachment K in the Pro Forma) and must satisfy the following nine principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. More specifically it must include sufficient detail to enable Transmission Customers to understand:

- i) The process for consulting with customers and neighbouring transmission providers;
- ii) The notice procedures and anticipated frequency of meetings;
- iii) The methodology, criteria, and processes used to develop transmission plans;
- iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;
- v) The obligations of and methods for 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 relevant cost allocation procedures or principles.

Demandes:

1.16 Please explain in detail the planning process of HQT.

R1.16

Voir la réponse à la question 6.1 de la demande de renseignements n° 1 du Regroupement national des Conseils régionaux de l'environnement du Québec (« RNCREQ ») et de l'Union des consommateurs (« UC »).

1.17 Please explain in detail how the planning process of HQT satisfies each of the nine principles specified by FERC in Order 890.

R1.17

Le processus de planification en place au Québec permet d'atteindre les objectifs recherchés par la FERC pour solutionner des problèmes propres aux réseaux américains.

1.18 Please explain in detail how the planning process of HQT addresses the eight issues that should be understood by Transmission Customers?

R1.18

Voir la réponse à la question 1.17.

1.19 Where in the HQT tariff proposal is the planning process documented?

R1.19

Le processus de planification du transporteur n'est pas présenté dans les *Tarifs et conditions*. Le plus récent document faisant état du processus de planification du transporteur a été déposé à la Régie dans le cadre de la Demande relative à la modification des conditions des services de transport (R-3669-2008).

Voir la réponse à la question 6.1 de la demande de renseignements n° 1 du Regroupement national des Conseils régionaux de l'environnement du Québec (« RNCREQ ») et de l'Union des consommateurs (« UC »).

Préambule

Section 16.1 (e) of the FERC Pro Forma requires a Transmission Customer to provide "the information required by the Transmission Provider's planning process". It is also required in Section 17.2 (x) as part of a Completed Application. The HQT proposal does not specify a requirement for planning information provision in Section 16.1 or in Section 17.2.

Demandes:

- 1.20 Why is this planning information provision obligation of the Transmission Customer not added to Section 16.1 and Section 17.2?

R1.20

Puisque les modifications aux *Tarifs et conditions* pour lesquelles le Transporteur demande l'approbation de la Régie ne portent pas sur l'appendice K et que les articles 16.1 et 17.2 du *tarif pro forma joint* à l'ordonnance 890-B réfèrent à l'appendice K, le Transporteur n'exige pas de ses clients les informations additionnelles requises en vertu de l'appendice K.

- 1.21 Does this planning information obligation exist in a different section of the HQT tariff? If so, where?

R1.21

Les *Tarifs et conditions* ne traitent pas du processus de planification au sens de l'appendice K.

PÉNALITÉS LIÉES À L'EXPLOITATION

2. **Références :** (i) HQT-1, Document 1, pages 20-21
(ii) HQT-2, Document 1, article 3
(iii) Ordonnance de la FERC 890B, OATT article 3

Préambule :

Référence (i) à la p. 20 :

« Pour promouvoir l'utilisation et l'acquisition ordonnées du service de transport, l'ordonnance no 890 prévoit des pénalités d'exploitation, par exemple pour l'utilisation du réseau sans réservation ou au-delà de la capacité réservée. Le montant de la pénalité est laissé au gré du fournisseur

**RESPONSE TO QUESTIONS 6.5 AND 6.6 OF
THE REQUEST FOR INFORMATION No. 1
PRESENTED BEFORE THE RÉGIE BY
REGROUPEMENT NATIONAL DES CONSEILS
RÉGIONAUX DE L'ENVIRONNEMENT DU QUÉBEC AND
UNION DES CONSOMMATEURS**

**RESPONSE TO QUESTIONS 6.5 AND 6.6 OF THE REQUEST FOR INFORMATION NO. 1
PRESENTED BEFORE THE REGIE BY REGROUPEMENT NATIONAL DES CONSEILS
RÉGIONAUX DE L'ENVIRONNEMENT DU QUÉBEC AND UNION DES CONSOMMATEURS**

1. I am asked to answer the following questions:

R6.5. Does the Transmission Provider's planning process comply with the principles and other requirements of Order 890, described in paragraphs 444 ff.? If it does, please specify how the Transmission Provider's process meets the FERC's requirements. If it does not, please indicate exactly why the Transmission Provider considers that it should not modify its planning process so as to meet the said requirements, in regard to the following components:

- 6.5.1 Coordination (§445 to 454)
- 6.5.2 Openness (§455 to 460)
- 6.5.3 Transparency (§461 to 479)
- 6.5.4 Information Exchange (§480 to 488)
- 6.5.5 Comparability (§489 to 495)
- 6.5.6 Dispute Resolution (§496 to 503)
- 6.5.7 Regional Participation (§504 to 528)
- 6.5.8 Economic Planning Studies (§529 to 551)
- 6.5.9 Cost Allocation for New Projects (§552 to 561)
- 6.5.10 Independent Third-Party Coordinator (§562 to 568)
- 6.5.11 State Commission Participation (§569 to 575)
- 6.5.12 Flexibility in Implementation (§576 to 582)
- 6.5.13 Recovery of Planning Costs (§583 to 586)
- 6.5.14 Open Season for Joint Ownership (§587 to 594)
- 6.5.15 Specific Study Processes Beyond Reliability and Congestion Reduction (§595 to 599)
- 6.5.16 Level of Detail in OATT (§600 to 602)

R6.6. Please specify, for each of the components mentioned in paragraph 602 of Order 890, why the Transmission Provider does not consider that such component should be included in its Rates and Conditions.

I. INTRODUCTION

2. In my rebuttal testimony of July 3rd, 2009 focussing on the U.S. FERC Order 890, which requires that jurisdictional U.S. transmission providers provide a description of their coordinated, open and transparent transmission planning process as an Attachment K to their Open Access Transmission Tariff ("OATT"), I arrived at a number of conclusions, including the following:¹
 - (a) Order 890 was part of a multi-pronged effort to resolve U.S. transmission problems in light of the 2003 blackout, a galvanizing event in the history of the U.S. power industry;
 - (b) FERC believed there to be a need for Attachment K for two reasons. The first and primary reason was that acute U.S. transmission problems could, in part, be solved by improved planning. The problems included: (1) insufficient transmission investment, (2) significant transmission congestion, (3) reliability problems and (4) the lack of coordination. The second reason was, in FERC's view, that inadequate planning might facilitate discrimination by transmission providers. In other words, U.S. grid conditions and deficiencies were the causes of ordering Attachment K filings in the U.S.;
 - (c) There are major differences between the situation of U.S. utilities and TransEnergie, and also between TransEnergie and other Canadian transmission providers, including differences regarding transmission congestion, transmission investment, the number of key regulators, transmission providers and independent power producers (IPPs), in addition to the characteristics of TransEnergie's Interconnection as a separate Interconnection performing Interconnection planning;
 - (d) For the reasons discussed more fully in my July 3rd Testimony, it is not necessary to add an Attachment K to TransEnergie OATT to achieve a well-functioning planning system, to improve the existing process or to meet the requirements for reciprocity; and
 - (e) Components of TransEnergie's current transmission planning processes reviewed in my July 3rd Testimony, when compared to U.S. utilities, provide for transmission planning equal to or superior in terms of meeting the goals of coordinated, open and transparent planning.
3. In light of these conclusions, I do not believe that TransEnergie has to adopt Attachment K or modify its existing planning process, as suggested by questions 6.5 and 6.6, to offer open and comparable access to its transmission system.
4. Given the breadth of questions 6.5 and 6.6 however, it might be helpful to particularize my response on certain points and draw the Regie's attention to certain additional elements of relevance to these questions.
5. To this end, I will organize my response around the following statements:

¹ Exhibit HQT-12, p. 10-13, 23, 28 and 52.

- (a) Why is it not necessary for TransEnergie to adopt Attachment K in order to offer open and comparable access to its transmission system.
- (b) Even assuming, for purposes of discussion, that the reasons for which FERC believed there was a need for Attachment K apply to the TransEnergie system, which is not the case, why do the various elements of TransEnergie's actual planning processes, when combined, given TransEnergie's unique situation and the regulatory environment in which it operates, allow TransEnergie to offer coordinated, open and transparent planning that is comparable to Attachment K.

II. WHY IS IT NOT NECESSARY FOR TRANSENERGIE TO ADOPT ATTACHMENT K IN ORDER TO OFFER OPEN AND COMPARABLE ACCESS TO ITS TRANSMISSION SYSTEM.

- 6. TransEnergie is not regulated by FERC and is not obligated to file Attachment K under U.S. FERC Order 890 principles and other requirements.² Thus, the premise of question 6.5 "*does TransEnergie comply with the requirements and principles*", namely that TransEnergie is obligated to comply with and file Attachment K, is incorrect.
- 7. The failures discussed below do not exist for TransEnergie and the Regie does not have to fix U.S. problems. TransEnergie is successfully providing open and comparable access service. It is an important principle that the Regie ensures that reciprocity is not misused even inadvertently to achieve goals of FERC that exceed the requirements for open and comparable access and that are inapplicable to TransEnergie's situation.
- 8. As stated above, there were two types of U.S. failures that resulted in Attachment K and the additional requirements for entities regulated by FERC. First, FERC was concerned about acute U.S. transmission system deficiencies, namely: (1) the lack of transmission investment by transmission providers, (2) the existence of significant and recurring congestion on the transmission system, (3) the existence of reliability problems, and (4) the lack of coordination among components of the interconnected transmission system.
- 9. Second, FERC was concerned that U.S. transmission planning lacked transparency and would use transmission planning to discriminate against unaffiliated companies. One consequence of the discrimination would be the lack of transmission and the other problems identified above. Another consequence would be higher prices for power.
- 10. My views in support of this first statement and the answer to questions 6.5 and 6.6 are directly associated with the issues of transmission congestion, transmission investments, transparency and coordination mechanisms.

A. THE ABSENCE OF CONGESTION WITHIN TRANSENERGIE'S TRANSMISSION SYSTEM

- 11. A key aspect of potential discrimination discussed in Order 890 is the existence of "significant and recurring congestion".³ Thus, it is necessary to understand whether there is "significant and recurring congestion" within the TransEnergie Interconnection when assessing the potential for discrimination and the type of coordinated, open and transparent transmission planning needed.

² Exhibit HQT-12, p. 6.

³ Order 890, par. 534 and 535.

1. TransEnergie's design criteria based on the absence of congestion

(a) The HQT Point configuration

12. I understand that TransEnergie's network is strongly radial and is based along high voltage lines connecting large remote hydro production centers to a major load center located in the southern part of Quebec, mainly in the Montréal region. It is also electrically isolated from the neighbouring systems as it is not synchronised with them. Providing for the local load therefore relies on the ability to reliably transfer power from remote generation without being able to rely on instantaneous support from neighbouring systems. As a consequence, I am told that TransEnergie's network has been developed to avoid congestion on the main system in order to be able to provide reliable service to the Quebec local load at all times using generation sources situated on its system.⁴
13. The absence of congestion is demonstrated in Table 1 entitled "Transmission System Use Rate in 2008". Regardless of the month or the service, the system never reaches a 100% of capability. Peak demand is assumed to be at very high levels and transmission capacity is determined through simulations under N-0 conditions, i.e., with all transmission facilities in service.⁵

Table 1
Transmission System Use Rate in 2008

	Native load	Overall (native load and point to point)
January	90.3%	96.7%
February	84.7%	95.4%
March	76.9%	87.4%
April	70.3%	81.8%
May	59.6%	67.7%
June	52.3%	64.4%
July	54.7%	65.4%
August	54.0%	65.7%
September	55.6%	67.1%
October	65.9%	72.5%
November	73.8%	84.7%
December	85.3%	90.6%

14. As explained by TransEnergie, its planning criteria call for no congestion under normal events (e.g., all facilities are in operation, also referred to as N-0 conditions):

⁴ Exhibit HQT-27 titled "HQT Point", prepared by TransEnergie, December 2008.

⁵ Transmission System Planning, Exhibit HQT-20, p. 13.

Normal events are those which the system must handle regularly with no loss of load. The criteria addressing such events set out the level of robustness the system must have in order to meet transmission needs securely while providing the expected quality of service. Complying with these criteria involves adding facilities to the existing system structure, thus modifying the system architecture.

Off-normal events are more extreme and less probable than normal events. They cannot be covered at all times unless considerable investments are made to increase considerably system robustness. To deal with such events, the Transmission Provider uses special protection systems, such as generation rejection and load shedding, to limit system degradation.⁶

(b) NPCC Process

15. TransEnergie is a participant in the Northeast Power Coordinating Council (NPCC) reliability assessment process. Therefore, TransEnergie provides planning information to the NPCC which is available to NPCC members,⁷ including detailed information on its design criterion. I understand that TransEnergie is subject to audits by NPCC which confirm the absence of congestion on the TransEnergie system under normal conditions.

2. The TLR Log confirms the absence of congestion

16. The Transmission Loading Relief (TLR) Log describes instances in which TransEnergie had to undertake actions to prevent system overloads.
17. Our analysis of the loading relief on TransEnergie system limits with or without curtailment of service for the period of June 1st, 2009 to May 31st, 2010⁸ confirms that internal congestion (i.e. not involving Interconnection interties) was limited to a few situations in which contingencies had occurred, i.e. one or more system elements were not available due to maintenance or equipment failure, and the instances of required relief were rare. In no case did congestion within TransEnergie result in curtailment of firm point to point service and hence, the required relief was minor system adjustments.
18. Planning criterion to have no internal congestion under N-0 conditions, i.e. with all transmission facilities in service, is unique to TransEnergie. None of the three major Interconnections in North America (the Eastern Interconnect, the Western Electric Coordinating Council (WECC), and the Electric Reliability Council of Texas (ERCOT)) has such a demanding planning criterion.

⁶ Transmission System Planning, Exhibit HQT-20, p. 8.

⁷ Procedures for System Modeling: Data Requirements & Facility Ratings, NPCC, March 2007, Exhibit HQT-26.

⁸ Exhibit HQT-15.

3. Implications of the absence of significant and recurring congestion

19. The absence of "significant and recurring congestion" eliminates one of the key predicates to Order 890 and the need for its provisions designed to ameliorate this problem.⁹
20. It also eliminates the need for economic planning studies and cost allocation procedures as raised by Order 890.
21. Furthermore, the absence of congestion confirms the adequacy of TransEnergie investment in its transmission grid.

B. AN ADEQUATE LEVEL OF AUTHORIZED INVESTMENTS

1. The investment projects on TransEnergie's network and comparison with the situation in the U.S.

(a) TransEnergie's investments since 2002

22. I understand that TransEnergie is subject to the authority of the Régie when performing electric power transmission activities. Under Section 73 of the Act Respecting the Régie de l'énergie, TransEnergie must obtain the authorization of the Régie to acquire, build or dispose of power transmission assets or to expand or modify the use of the transmission system.¹⁰
23. I am informed that since 2002, capital projects in transmission representing investments of \$7.70 Billion on TransEnergie's network have been approved by the Régie.¹¹ This corresponds to an investment average of \$24/KW of peak load.
24. The approved investments for the period of 2006 to 2010 correspond to an investment level of \$31/kW, which is higher than the previous projection of \$26/kW, as analyzed in my July 3rd Testimony.¹² These new figures even increase the gap between the historical level of investments in the U.S. compared with the situation of TransEnergie. Both the \$26/kW and the \$31/kW of TransEnergie 2006 to 2010 transmission investment exceed the \$11/kW in US transmission investment in the last year of data available to FERC when it initiated the FERC Order 890 process and the \$18/kW of US transmission investment for 2006 to 2010 analyzed in my July 3rd Testimony.¹³

⁹ See paragraphs 534 and 535 of Order 890.

¹⁰ Process for Approval of Capital Projects by the Régie de l'énergie, Exhibit HQT-18. The web link to the Act Respecting the Régie de l'énergie:

http://www2.publicationsduquebec.gouv.qc.ca/dynamicSearch/telecharge.php?type=2&file=/R_6_01/R6_01_A.html;

The web link to the Regulation respecting the conditions and cases where authorization is required from the Régie de l'énergie:

http://www2.publicationsduquebec.gouv.qc.ca/dynamicSearch/telecharge.php?type=3&file=/R_6_01/R6_01R2_A.HTM.

¹¹ Capital Projects in Transmission, Exhibit HQT-16.

¹² July 3rd Testimony, p. 50.

¹³ July 3rd Testimony, p. 30-32

(b) Hydro-Québec Strategic Plan 2009-2013

25. I understand that TransEnergie presents its strategic plan for approval to a parliamentary commission composed of elected representatives. This open review by elected officials is a public process during which interested persons may participate.¹⁴
26. The 2009-2013 Strategic Plan of Hydro-Québec confirms that investments totalling \$7.822 Billion are projected by TransEnergie for the same period, including \$4.1 Billion for transmission capacity increase to meet customer's needs.¹⁵
27. This projection for 2009 to 2013 corresponds to an additional increase in the investment capital projects in transmission on the TransEnergie's network. The 2009 to 2013 projection of \$42/KW is even higher than the earlier periods. The most recent projected US transmission investment over the 2009 to 2013 period is \$22/KW or slightly more than one-half TransEnergie's investment level.¹⁶
28. In sum, the adequacy of transmission investment by TransEnergie eliminates another key predicate to Order 890 and the need for its provisions designed to ameliorate the lack of investment. The adequacy of investment also establishes that TransEnergie meets the comparability requirements of Order 890 in that all transmission service requests are being fulfilled.

C. MEASURES IN PLACE ENSURING TRANSPARENCY

1. Information provided by TransEnergie on network planning

(a) Authorization Process under Section 73 of the Act

29. As mentioned above, investment made by TransEnergie on its transmission system is subject to the Régie's authorization. I understand that in cases where a customer's transmission service request necessitates additions to the system, the process of seeking the Régie's authorization is preceded by a System Impact Study and a Facilities Study as required in TransEnergie OATT.¹⁷
30. To obtain the Régie's authorization, TransEnergie must meet specific conditions and provide information as required in the Regulation respecting the conditions and cases where authorization is required from the Régie de l'énergie.¹⁸ These conditions and information are different depending on whether the projects are worth \$25 million or more, in which case they are studied individually, or they are worth less than \$25 million, in which case they are grouped together and studied by investment category.¹⁹

(i) Projects worth \$25 million or more:

¹⁴ See the *Hydro-Quebec Act*, Section 11.13.

¹⁵ HQ's Strategic Plan 2009-2013, Exhibit HQT-17, p. 37 and 41.

¹⁶ EEI 2009 Financial Review Plus 2010 Developments, Annual Report of the US Shareholder Owned Electric Utility Industry. p. 58; NERC Energy Supply and Demand

¹⁷ Process for Approval of Capital Projects by the Régie de l'énergie, Exhibit HQT-18.

¹⁸ Regulation respecting the conditions and cases where authorization is required from the Régie de l'énergie; Exhibit HQT-18.

¹⁹ Exhibit HQT-18.

These projects are filed individually and studied individually by the Regie. All requests for authorization of such projects by HQT must be accompanied by the following information:

- (1) the project objectives;
- (2) the project description;
- (3) the justification of the project with regard to the objectives;
- (4) the project costs;
- (5) the project feasibility study;
- (6) the list of authorizations required under other laws;
- (7) the impact on the rates including a sensitivity analysis;
- (8) the impact on the reliability of the electric power transmission system and on the quality of the electric power transmission service;
- (9) any other solutions contemplated, which must include the information referred to in the preceding paragraphs;
- (10) according to the nature of the project, the list of the principal technical standards applicable to the project;
- (11) the contractual commitments of the consumers of the service and their financial contributions, where applicable.

(ii) **Projects worth less than \$25 million:**

In accordance with the Regulation, investments related to projects worth less than \$25 million are presented by investment category (without project-by-project breakdown). The categories used by HQT are as follows:

- (1) Asset sustainment;
- (2) System quality improvements;
- (3) Compliance with standards and requirements;
- (4) Growth of the needs of HQT's clientele.

All such requests for authorization must include the following information:

- (1) the descriptive summary of the investments and their objectives;
- (2) the costs based on the investment category;

- (3) the justification of the investments with regard to the objectives;
 - (4) the impact on rates;
 - (5) the impact on the reliability of the electric power transmission system and the quality of the electric power transmission service.²⁰
31. This process is separate from, and supplemental to tariff cases. It is a review that is open to interested persons and that allows intervenors from both inside and outside Quebec with interests in TransEnergie transmission investment. This process provided by law allows for examination of witnesses. The process is subject to public notice. Transmission investments and plans are subject to challenge by intervenors.
32. I understand that requests for approval of the TransEnergie's capital projects are posted on the Web site of the Regie under Section 4 of the Rules respecting the procedure of the Regie.
33. I also understand that:²¹
- (a) Any interested party may apply to the Regie for status as an intervenor in hearings on the TransEnergie's requests for approval of capital projects. Any other interested party may also file written observations on any issue pending before the Regie;
 - (b) Intervention of interested parties in these hearings is regularly allowed, in cases where the relevance of the interested party's contribution to the study of the file is shown, given the party's area of competency.
 - (c) Authorized intervenors participate in the hearings. They receive copies of the evidence filed by TransEnergie in support of its request. They may access documents and information identified as confidential by the Regie according to the provisions it sets forth, including the execution of a confidentiality agreement, and they may submit written requests to TransEnergie to obtain additional details on the evidence.
 - (d) Authorized intervenors also obtain the information relevant to the evaluation of the capital project, including the power flow diagrams, information about the project's impact on rates and on the quality of transmission service, information about alternative solutions that were considered but rejected by the TransEnergie, etc.
34. As stated above, the Regie has the power to issue orders to protect confidential information from disclosure to intervenors and third parties under conditions it sees fit.²² This process strikes the right balance between the desire for openness and transparency and the need to protect confidential information. It provides the equivalent

²⁰ Section 5 of the Regulation.

²¹ Exhibit HQT-18, p. 6 and 7.

²² Section 33 of the Rules respecting the procedure of the Régie de l'énergie.

of protection of confidential information and CEII (Critical Energy Infrastructure Information) consistent with FERC Order 890.

35. I am told that any party intervening in this process can ask the Regie for the recovery of its costs provided a budget is submitted and that the Regie itself can recover its costs from TransEnergie.²³

(b) Rate cases and aspect of network planning

36. In addition to Section 73 review, TransEnergie's OATT is subject to frequent open rate cases in a public and open process. Evidence of this appears from the list of Rate Cases Application since 2001.²⁴
37. Since 2000, there is a Transmission System Planning Description as part of TransEnergie's filing.²⁵
38. Such planning description provides information on system design and planning approach, transmission system growth, capital projects and commissionings projected over a ten-year horizon.²⁶
39. This process is also an open process subject to public notice.²⁷ Parties may intervene in this process in a manner similar to the authorization process under Section 73 and challenge recovery of transmission investments and operation and maintenance costs providing an additional avenue for input to the process. Intervenor can request additional information and documents explaining TransEnergie's plans via request for information and questions to witnesses.
40. As in the authorization process, I am told that parties can ask the Regie for the recovery of their costs²⁸ provided a budget is submitted.
41. In conclusion, this is a second process that provides stakeholders the opportunity to participate in the transmission planning process in an open and transparent manner under the Regie's overall control.

(c) Filing Guidelines before the Regie

42. It appears that the Regie has produced a document titled *Guide de dépôt pour Hydro-Québec dans ses activités de transport d'électricité*.²⁹ These filing guidelines apply to all requests for authorization of capital projects and rate cases.
43. It appears that for a project worth \$25 million or more, TransEnergie must describe alternatives considered to meet the objectives pursued and their advantages and drawbacks. It must also compare technical and economic studies and analyses that led

²³ Sections 36 of the Act and 35 of the Rules respecting the procedure of the Régie de l'énergie.

²⁴ System Planning and Rate Cases, Exhibit HQT-19.

²⁵ Exhibit HQT-19.

²⁶ Transmission System Planning, Exhibit HQT-20.

²⁷ Act respecting the Régie de l'énergie, Section 25.

²⁸ Sections 36 of the Act and 35 of the Rules respecting the procedure of the Régie de l'énergie.

²⁹ Process for Approval of Capital Projects by the Régie de l'énergie, Exhibit HQT-18.

to the choice of the project submitted for approval, along with single-line diagrams, relevant power flow diagrams and results of such project.

44. In short, considering the above, I find that the existing process has numerous opportunities for stakeholders to participate in an open and transparent planning process. Indeed, the process provides a level of redundancy that underlines a commitment to ensure that parties have the opportunity to have input and participate meaningfully in transmission planning. This redundancy includes the two processes (investment authorization and tariff cases) plus others discussed below, and the multiplicity of funded parties. This process meets or exceeds the Order 890 requirements with respect to the requirements for openness and transparency.
45. The Regie has consciously exercised its powers and assumed its responsibility for determining the proper implementation and goals with respect to either reliability or transmission planning.

(d) NPCC planning process

46. TransEnergie is a member of the NPCC. NPCC is one of the Regional Entities that has a delegation from the Electrical Reliability Organization (ERO) to perform some tasks associated with compliance monitoring and enforcement of reliability. The North American Electric Reliability Corporation (NERC) was designated as the ERO. NPCC includes the regions of Ontario, Quebec, New Brunswick, New York and New England. These entities are more specifically concerned about reliability issues.
47. As such, TransEnergie must satisfy its obligations as a member and consequently provide transmission planning information, including load flow information, planning criteria, basic methodology and processes. It must also identify planned upgrades and their status, monitored contingencies and the software used by TransEnergie. Such information is required to replicate the results of planning studies.
48. I understand that TransEnergie is complying with its obligations and is providing the right stakeholders with the right information.
49. NPCC provides an environment requiring members to participate in various task forces, working groups and other forums and to exchange information concerning transmission systems and the associated planning.
50. It is worth adding that NPCC reviews the transmission system, operations, planning and associated functions. This further underlines the transparency, openness and coordinated aspect of the NPCC process in which TransEnergie is participating.
51. In sum, the NPCC is another example of an already existing process providing for open and transparent transmission planning of the TransEnergie system. Stakeholders seeking to meaningfully participate in open and transparent planning also have this NPCC process available to them that helps facilitate coordination with other regions.

(e) Consultation process on environmental impact

52. I understand that Hydro-Québec's major projects are submitted to a mandatory environmental impact assessment and review process, which may trigger the intervention of the *Bureau d'audiences publiques sur l'environnement*, an independent body responsible for consulting stakeholders with respect to such projects. The

regulation provides that the environmental impact assessment that must be prepared by Hydro-Quebec must contain a description of the various options to the project put forth, including the project's location, the means and methods for carrying out and developing the project and the reasons justifying the option chosen.³⁰

53. More specifically, I refer to the document "Environmental Impact Assessment Process"³¹ describing the various steps of the consultation process, including the fact that the environmental impact assessment statement is made public, that the proponent of the project is given instructions to initiate the public information and consultation phase with respect to the project, that the file of any project subject to the environmental impact assessment and review process is made available to the public at reference centers in Quebec and Montréal and at a reference center in the region where the project is likely to be undertaken, and that public hearings ordered by the Minister are announced by means of a press release and notice on the Bureau's web-site as well as through a notice published in a daily and a weekly newspaper circulated in the region where the project is likely to be carried out, and in a daily newspaper in Quebec and in Montréal.
54. I am also told that Hydro-Québec regularly holds prior consultations with intervenors likely to be affected by one of its projects.
55. This provides another opportunity for input into the planning process and coordination.

(f) Exploratory Studies relating to the connection of generating stations

56. Under Section 12A.5 of TransEnergie's OATT, exploratory studies relating to the connection of generation stations is provided. Under this process, a "rough idea" of the feasibility of connecting planned generating station is provided. The purpose of the study is to provide an approximate parameter estimate of a single connection scenario.
57. The exploratory analysis is open to stakeholders and the costs are smaller (\$5,000) than for the performance of a regular System Impact Study.³²
58. This process gives the opportunity to stakeholders to investigate for a nominal fee alternative transmission scenarios and to obtain transmission system planning information. This is an example of the extent to which the TransEnergie planning process is open and transparent.

(g) Complaint Process

59. It appears from TransEnergie OATT that it is also subject to an open complaint process for any matters not resolved satisfactorily regarding the application of a tariff or an electricity transmission condition. The complaint is first addressed to TransEnergie's Marketing Director, who has 60 days following receipt of the written complaint to send TransEnergie's position and the reasons justifying it.
60. If the complainant is not satisfied with the result, he may file a complaint before the Regie.³³ A fast track procedure is also available for urgent questions regarding a

³⁰ Environmental Impact Assessment Process, Exhibit HQT-22.

³¹ Exhibit HQT-22.

³² Section 12A.5 of the TransEnergie OATT.

³³ Procedure for examining complaints from Hydro-Quebec TransEnergie's clients, Exhibit HQT-23.

rejected request for transmission service under certain circumstances subject to a five-working day delay for TransEnergie to provide its answer to the complaint.

61. This complaint process provides a review of TransEnergie's decision, including transmission planning decisions, and ensures an open and transparent process. In addition, it demonstrates that the process provides for timely oversight, comparability and dispute resolution.

(h) TransEnergie's neighboring systems discussion on planning and operation

62. TransEnergie is also involved in discussions on planning and operation with its neighboring systems as is more fully detailed in Sections II.A.1.(b), II.C.1.(d) and II.D.3. This is additional evidence that TransEnergie is providing the right stakeholders with the appropriate planning and related information.

(i) TransEnergie's Code of Conduct

63. TransEnergie's Code of Conduct is intended to prevent any form of preferential treatment toward its affiliates by controlling behaviour and the exchange of employees and information.³⁴
64. Section 4.18 of this Code confirms that transmission services provided by TransEnergie shall be in accordance with its OATT, that applications for transmission service submitted to TransEnergie by its affiliates shall be treated the same way as applications by non-affiliated customers and that TransEnergie shall apply its OATT to its affiliates the same way as to non-affiliated transmission customers.³⁵
65. These restrictions on TransEnergie's conduct aim to ensure open and comparable provision of transmission services, including transmission planning.

(j) System Impact Study Process

66. TransEnergie OATT establishes procedures for system impact studies (SIS) and provision of comparable transmission service, including for point to point service.³⁶
67. The SIS process allows for detailed studies of the TransEnergie grid and coordination between stakeholders requesting the studies and TransEnergie planners.
68. The content and scope of a SIS is described in Section 19 and Attachment D of TransEnergie OATT.
69. Copies of SIS are available to interested stakeholders upon request, at no charge.
70. I am told that no request for service has been rejected by TransEnergie and no complaint related to SIS or provision of service has been upheld against TransEnergie by the Regie.

³⁴ Transmission Provider Code of Conduct, Exhibit HQT-25, Section 3.1.

³⁵ Exhibit HQT-25.

³⁶ Section 19 of the TransEnergie OATT.

D. EXISTING COORDINATION MECHANISMS

71. The purpose of coordination in Order 890 is that within each regional grid transmission providers, state regulators, transmission customers and other stakeholders can participate in planning and that there be no discrimination in the provision of service.
72. In implementing coordination measures, flexibility should be given to each transmission provider to craft coordination requirements adapted to their situation and that of their stakeholders.³⁷

1. Coordination among Transmission Providers

73. In terms of coordination with Transmission Providers within the Interconnection, TransEnergie already meets Order 890's requirement. Indeed, TransEnergie has met this requirement as well if not better than any other of the 8 or 10 regional grids in the U.S.³⁸
74. TransEnergie coordination requirements necessarily reflect its unique situation relative to the rest of North America. Namely, TransEnergie is the only major transmission provider in Quebec and hence, cannot have major problems coordinating with other transmission providers within its Interconnection.
75. I understand that TransEnergie owns nearly the totality of the transmission in Quebec. TransEnergie's system has only one sub-region; indeed it is modeled as a single point (the "HQT Point") due to the absence of internal congestion.
76. TransEnergie is more than its own region: it is its own asynchronous Interconnection.³⁹ There are no other major Interconnections in North America with only one major transmission provider with anything close to owning almost all of the transmission. TransEnergie is not part of the same Interconnection as its contiguous geographic neighbors such as Ontario, New Brunswick, New York and New England.
77. Under Order 890, the primary coordination issue to be addressed is coordination within the Interconnection. In fact, in the discussion of regional coordination, there is no discussion of Interconnection to Interconnection coordination, but coordination among sub-regional grid components.⁴⁰

³⁷ FERC Order 890, para. 451, 452, 576 to 582.

³⁸ Exhibit HQT-12, p. 26

³⁹ HQT-12, p. 10. As I stated in my testimony, Interconnection refers to a synchronous transmission system. Movement between Interconnections requires conversions of power from AC to DC and then back to AC.

⁴⁰ This type of coordination represents the largest single section in the Commission's determination of Order 890. While this discussion is under the section on regional participation, it obviously bears on the requirements for coordination among transmission providers. Also, the example of the Western Electricity Coordinating Council (WECC) treatment by FERC as a single Interconnection is instructive, specifically considering that there is no discussion of coordination between WECC and other Interconnections but rather among the established sub-regions of WECC. TransEnergie's Grid is like the WECC; it too is its own Interconnection.

2. TransEnergie Coordination with State Regulators

78. In terms of coordinating with state regulators there is only one main regulatory authority involved in the TransEnergie system, namely the Regie. In contrast, the Eastern Interconnection has 43 state and provincial regulators in addition to FERC and NERC.
79. Thus, the need for coordination is less than for U.S. systems considering the fact that TransEnergie is its own Interconnection and is not subject to the same coordination challenges that exist in the U.S.

3. Other Coordination Mechanisms

80. TransEnergie is participating in discussions with various neighboring systems on planning and operation. As such, TransEnergie is party to two types of agreements with its neighboring systems: Asset Owner Agreements and Interconnection Agreements.⁴¹
81. First, the Asset Owner Agreements ensure, among other things, the reliability, operability and nominal transfer capability of the Interconnection facilities through coordinated operation, inspection, maintenance, planning, metering, and upgrades of the Interconnection facilities. The parties hold discussions as transmission asset owners.⁴²
82. Second, the Interconnection Agreements provide the establishment of an interconnection committee which will meet twice a year. Such agreements provide for the reliability and operability of the Interconnection facilities and for Emergency Service and Inadvertent Interchange accounting and procedures between Interconnected Systems.⁴³
83. Evidence exists that Interconnection to Interconnection coordination is fruitful. Namely, there are extensive existing AC-DC-AC interties to four other regions in the Eastern Interconnect and proposals to expand the tie lines into ISO-NE which FERC recently approved.
84. There are also numerous avenues for coordination with transmission customers, including investment project authorization process under Section 73 of the Act, rate cases, NPCC planning process, consultation process on environmental impact, exploratory studies, complaint process and SIS process. These avenues are discussed in more details under Section II.C.1 above.
- III. WHY DO THE VARIOUS ELEMENTS OF TRANSENERGIE'S ACTUAL PLANNING PROCESSES, WHEN COMBINED, GIVEN TRANSENERGIE'S UNIQUE SITUATION AND THE REGULATORY ENVIRONMENT IN WHICH IT OPERATES, ALLOW TRANSENERGIE TO OFFER COORDINATED, OPEN AND TRANSPARENT PLANNING THAT IS COMPARABLE TO ATTACHMENT K.**
85. In my view, TransEnergie does not need to file an Attachment K.
86. I say this because the problems that exist in the U.S., in response to which FERC believed that there was a need for Attachment K, do not exist for TransEnergie.

⁴¹ Hydro-Quebec TransEnergie, Meetings with Neighbouring Systems, Exhibit HQT-24.

⁴² Exhibit HQT-24.

⁴³ Exhibit HQT-24.

87. I also say this because, in my view, TransEnergie already offers coordinated, open and transparent planning that is comparable to Attachment K.
88. In support of this position, it is important to highlight a key aspect of Order 890 referred to several times, including in subquestion 6.5.12, namely flexibility to devise a system appropriate to the requirements of stakeholders and specific system conditions (see paragraphs 576 to 582 of Order 890).
89. In answer to subquestions 6.5.1 to 6.5.9, and for the reasons already discussed, it is my opinion that the existing planning processes described above satisfy Order 890 goals and requirements concerning:
- (a) Coordination (see paragraphs 29-41, 46-62, 66-70, and 71-84, above);
 - (b) Openness (see paragraphs 15, 25, and 29-70, above);
 - (c) Transparency (see paragraphs 29-70, above);
 - (d) Information Exchange (see paragraphs 29-70, above);
 - (e) Comparability (see paragraphs 11-29, 22-41, 56-61, and 63-70, above);
 - (f) Dispute Resolution (see paragraphs 22, 25-45, 52-55, 59-61, and 63-70, above);
 - (g) Regional Participation (see paragraphs 46-51, 62, and 71-84, above);
 - (h) Economic Planning Studies (see paragraphs 11-28, above);
 - (i) Cost Allocation for New Projects (see paragraphs 11-28, above).
90. In answer to subquestion 6.5.15, I am of the view that FERC requirements regarding Specific Study Processes Beyond Reliability and Congestion Reduction are complied with (see paragraphs 29-41, 52, 56-58, , 66-70, above).
91. In answer to subquestion 6.5.11, I am of the view that FERC requirements for State Commission participation are not applicable in the absence of the existence of multiple States or regulatory entities in the Interconnection. This is an example of the importance of flexibility in tailoring transmission planning requirements to the specific circumstances of the system.
92. Finally, with respect to elements referred to in RNCREQ's Request for particulars that have not been retained by FERC as requirements of Attachment K (subquestions 6.5.10, 6.5.13 and 6.5.14), it is my opinion that:
- (a) The performance of TransEnergie is sufficient so as not to require an Independent Third Party Coordinator, which is not a requirement of Attachment K;⁴⁴

⁴⁴ Order 890, par. 567.

- (b) FERC comments regarding Recovery of Planning Costs, which is not a requirement of Attachment K,⁴⁵ are complied with (see paragraphs 35 and 40, above);
 - (c) Open Seasons for Joint Ownership, which are not requirements of Attachment K,⁴⁶ are not needed given the level of investments and upgrades (see paragraphs 22-28, above);
93. In light of the foregoing, I believe that even if there are specific differences in TransEnergie's planning compared to Attachment K, it still overall can meet reciprocity requirements due to the overall superiority of some elements and local conditions in terms of providing open and comparable access.
94. In particular, it is my view that TransEnergie would not need to have a section by section or line by line compliance to meet reciprocity requirements for open and comparable access in part due to the importance of flexibility in Order 890, the overall superiority of the TransEnergie situation and suitability of the TransEnergie process for producing and supporting an open and comparable access transmission system.

IV. CONCLUSION

95. TransEnergie is offering open, transparent and coordinated transmission planning and it needs not modify its existing planning process in order to offer open and comparable access to its transmission system.
96. The reasons for which FERC believed there was a need for Attachment K do not exist for TransEnergie, and the Regie simply does not have to intervene in order to fix U.S. problems.

⁴⁵ Although recovery of planning costs is not a formal requirement of Attachment K, it is commented upon by in Order 890, at par. 586.

⁴⁶ Order 890, par. 594.

