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Preventing Undue Discrimination and Preference in Transmission Service; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 37

[Docket Nos. RM05–17–000 and RM05–25–000; Order No. 890]

Preventing Undue Discrimination and Preference in Transmission Service

Issued February 16, 2007.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the regulations and the *pro forma* open access transmission tariff adopted in Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The final rule is designed to: Strengthen the *pro forma* open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination; provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and increase transparency in the rules applicable to planning and use of the transmission system.

EFFECTIVE DATE: This rule will become effective May 14, 2007.

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

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 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 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 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

[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).

[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.''

[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 (EPAct 2005). *See* Pub. L. 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 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 EPAct 2005.

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 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.

10. In the first few decades after enactment of the Federal Power Act (FPA) in 1935, the industry was characterized mostly by self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and investor-owned utilities connected to each utility's transmission system. Each system covered a limited service area, which was defined by the retail franchise decisions of State regulatory agencies. This structure of separate systems arose naturally primarily due to cost and the technological limitations on the distance over which electricity could be transmitted.

11. A number of statutory, economic, and technological developments in the 1970s led to an increase in coordinated operations and competition. Among those was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA),[6] which was designed to lessen dependence on foreign fossil fuels by encouraging the development of alternative generation sources and imposing a mandatory purchase obligation on utilities for generation from such sources. PURPA also enabled the Commission to order wheeling of electricity under limited circumstances.[7] The rapid expansion and performance of the independent power industry following the enactment of PURPA demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power. During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. The economic and technological changes in the transmission and generation sectors helped encourage many new entrants in the generating markets that could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, it became increasingly clear that the potential consumer benefits that could be derived from these technological advances could be realized only if more efficient generating plants could obtain access to the regional transmission grids. Because many traditional vertically integrated utilities still did not provide open access to third parties and favored their own generation if and when they

[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).

[6] Pub. L. 95–617, 92 Stat. 3117 (1978) (codified in U.S.C. titles 15, 16, 26, 30, 42, and 43).

[7] Section 211 of the FPA, 16 U.S.C. 824j. In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the U.S. Supreme Court's decision in *Otter Tail Power Company* v. *United States,* 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with Federal power marketing agencies. *See, e.g., Consumers Power Co.,* 6 NRC 887, 1036–44 (1977); *Toledo Edison Co.,* 10 NRC 265, 327–34 (1979); *Florida Municipal Power Agency* v. *Florida Power and Light Co.,* 839 F. Supp. 1563 (M.D. Fla. 1993).

provided transmission access to third parties, access to cheaper, more efficient generation sources remained limited.

12. The Commission encouraged the development of independent power producers (IPPs), as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis, and by encouraging more widely available transmission access on a case-by-case basis. Market-based rates helped to develop competitive bulk power markets by allowing generating utilities to move more quickly and flexibly to take advantage of short-term or even long-term market opportunities than those utilities operating under traditional cost-of-service tariffs. In approving these market-based rates, the Commission required that the seller and its affiliates lack market power or mitigate any market power that they may have had.[8] The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby drive up prices. A key inquiry became whether the seller or its affiliates owned or controlled transmission facilities in the relevant service area and therefore, by denying access or imposing discriminatory terms or conditions on transmission service, could foreclose other generators from competing. Beginning in the late 1980s, in order to mitigate their market power to meet the Commission's conditions, public utilities seeking Commission authorization for blanket approval of market-based rates for generation services under section 205 of the FPA filed ''open access'' transmission tariffs of general applicability.[9] The Commission also approved proposed mergers under section 203 of the FPA on the condition that the merging companies remedy anticompetitive effects potentially caused by the merger by filing ''open access'' tariffs. The early tariffs submitted in market-based rate proceedings under section 205 and merger proceedings under section 203 did not, however, provide access to the transmission system that was comparable to the service the transmission providers used for their own purposes. Rather, they typically made available only point-to-point transmission service, *i.e.*, service from a single point of receipt to a single point of delivery. As these early tariffs were offered only by transmission providers that volunteered to provide service to third parties, they resulted in a patchwork of open access that was not sufficient to facilitate wholesale generation markets.

13. In response to the competitive developments following PURPA, and the fact that limited transmission access and significant regulatory barriers continued to constrain the development of generation by independent power producers, Congress enacted Title VII of the Energy Policy Act of 1992 (EPAct 1992).[10] EPAct 1992 reduced regulatory barriers to entry by creating a class of ''Exempt Wholesale Generators'' that were exempt from the requirements of the Public Utility Holding Company Act of 1935.[11] EPAct 1992 also expanded the Commission's authority to approve applications for transmission services under sections 211 and 212 of the FPA.[12] Though the Commission aggressively implemented expanded section 211, it ultimately concluded that the procedural limitations in section 211 thwarted the Commission's ability to effectively eliminate undue discrimination in the provision of transmission service.

B. Order No. 888 and Subsequent Reforms

14. In April 1996, as part of its statutory obligation under sections 205 and 206 of the FPA to remedy undue discrimination, the Commission adopted Order No. 888 prohibiting public utilities from using their monopoly power over transmission to unduly discriminate against others. In that order, the Commission required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs that contained minimum terms and conditions of non-discriminatory service. It also obligated such public utilities to ''functionally unbundle'' their generation and transmission services. This meant public utilities had to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs, and to separately state their rates for wholesale generation, transmission and ancillary services.[13] Each public utility was required to file the *pro forma* OATT included in Order No. 888 without any deviation (except a limited number of terms and conditions that reflect regional practices).[14] After the effectiveness of their OATTs, public utilities were allowed to file, pursuant to section 205 of the FPA, deviations that were consistent with or superior to the *pro forma* OATT's terms and conditions. Because certain owners, controllers or operators of interstate transmission facilities were not subject to the Commission's jurisdiction under sections 205 and 206 and thus were not subject to Order No. 888, the Commission adopted a reciprocity provision in the *pro forma* OATT that conditions the use by a non-public utility of a public utility's open access services on an agreement to offer non-discriminatory transmission services in return.

15. In addition to imposing the functional unbundling requirement, the Commission also encouraged broader reforms through the formation of independent system operators (ISOs). The Commission stated that ISOs can provide significant benefits such as enhancing regional efficiencies and further remedying undue discrimination.[15] While the Commission declined to mandate ISOs, it set forth eleven principles for assessing ISO proposals submitted to the Commission.[16]

16. Order No. 888 also clarified the Commission's interpretation of the Federal and State jurisdictional boundaries over transmission and local distribution. While Order No. 888 reaffirmed that the Commission has exclusive jurisdiction over the rates,

[8] *See, e.g., Dartmouth Power Associates Limited Partnership,* 53 FERC ¶ 61,117 (1990); *Commonwealth Atlantic Limited Partnership,* 51 FERC ¶ 61,368 (1990); *Doswell Limited Partnership,* 50 FERC ¶ 61,251 (1990); *Citizens Power & Light Co.,* 48 FERC ¶ 61,210 (1989); *Ocean State Power,* 44 FERC ¶ 61,261 (1988); and *Orange and Rockland Utilities, Inc.,* 42 FERC ¶ 61,012 (1988).

[9] *See* Order No. 888 at 31,644 n.52.

[10] Pub. L. 102–486, 106 Stat. 2776 (1992) (codified at, among other places, 15 U.S.C. 79z–5a and 16 U.S.C. 796 (22–25), 824j–l).

[11] 15 U.S.C. 79a, *repealed by* EPAct 2005 sec. 1263; *see Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005,* Order No. 667, 70 FR 75592 (Dec. 20, 2005), FERC Stats. & Regs. ¶ 31,197 (2005), *order on reh'g,* Order No. 667–A, 71 FR 28446 (May 16, 2006), FERC Stats. & Regs. ¶ 31,213 (2006), *order on reh'g,* Order No. 667–B, 71 FERC 42750 (Jul. 28, 2006), FERC Stats. & Regs. ¶ 31,224 (2006), *reh'g pending.*

[12] 16 U.S.C. 824j (authorizing the Commission to require transmission utilities to provide service in certain circumstances); 16 U.S.C. 824k (establishing rates for service provided pursuant to an order under section 211).

[13] This is known as ''functional unbundling'' because the transmission element of a wholesale sale is separated or unbundled from the generation element of that sale, although the public utility may provide both functions. *See infra* section IV.B.4 of this Final Rule.

[14] *See* Order No. 888 at 31,769–70 (noting that the *pro forma* OATT expressly identified certain non-rate terms and conditions, such as the time deadlines for determining available transfer capability in section 18.4 or scheduling changes in sections 13.8 and 14.6, that may be modified to account for regional practices if such practices are reasonable, generally accepted in the region, and consistently adhered to by the transmission provider).

[15] Order No. 888 at 31,655.

[16] *Id.* at 31,730–32.

terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, it nevertheless recognized the legitimate concerns of State regulatory authorities regarding the transmission component of bundled retail sales. The Commission therefore declined to extend its unbundling requirement to the transmission component of bundled retail sales. On appeal, the U.S. Supreme Court affirmed this element of Order No. 888, finding that the Commission made a statutorily permissible choice.[17]

17. The same day it issued Order No. 888, the Commission issued a companion order, Order No. 889,[18] addressing the separation of vertically integrated utilities' transmission and merchant functions, the information transmission providers were required to make public, and the electronic means they were required to use to do so. Order No. 889 imposed Standards of Conduct governing the separation of, and communications between, the utility's transmission and wholesale power functions, to prevent the utility from giving its merchant arm preferential access to transmission information. All public utilities that owned, controlled or operated facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an Open Access Same-Time Information System (OASIS) that was to provide existing and potential transmission customers the same access to transmission information.

18. Among the information public utilities were required to post on their OASIS was the transmission provider's calculation of ATC. Though the Commission acknowledged that before-the-fact measurement of the availability of transmission service is ''difficult,'' it concluded that it was important to give potential transmission customers ''an easy-to-understand indicator of service availability.'' [19] Because formal methods did not then exist to calculate ATC and total transfer capability (TTC), the Commission encouraged industry efforts to develop consistent methods for calculating ATC and TTC.[20] Order No. 889 ultimately required transmission providers to base their calculations on ''current industry practices, standards and criteria'' and to describe their methodology in their tariffs.[21] The Commission noted that the requirement that transmission providers purchase only ATC that is posted as available ''should create an adequate incentive for them to calculate ATC and TTC as accurately and as uniformly as possible.'' [22]

19. The electric industry continued to undergo economic and regulatory changes in the years following the issuance of Order No. 888. Retail access was adopted by approximately 25 states in the late 1990s.[23] This State restructuring activity spurred significant changes at the wholesale level as well by encouraging or requiring the divestiture of generation plants by traditional electric utilities and the development of ISOs that could manage short-term energy markets necessary to support retail access. At the same time, there was a significant increase in the number of mergers between traditional electric utilities and between electric utilities and gas pipeline companies, and large increases in the number of power marketers and independent generation facility developers entering the marketplace. Trade in bulk power markets increased significantly and the Nation's transmission grid was used more heavily and in new ways as customers took advantage of the *pro forma* OATT and purchased power from competitive sellers.

20. In the wake of these changes, in December 1999, the Commission adopted Order No. 2000.[24] That rulemaking recognized that Order No. 888 set the foundation upon which competitive electric markets could develop, but did not eliminate the potential to engage in undue discrimination and preference in the provision of transmission service.[25] The rulemaking also recognized that Order No. 888 did not address the regional nature of the grid, including the treatment of parallel flows, pancaked rates, and congestion management. Thus, the Commission encouraged the creation of RTOs to address important operational and reliability issues and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. The Commission found that RTOs would increase the efficiency of wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently, and operating markets for 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 infrastructure development and its role in facilitating the development of competitive wholesale markets. The Congressional directives in EPAct 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

[17] *New York* v. *FERC,* 535 U.S. 1 (2002).

[18] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct,* Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

[19] Order No. 889 at 31,605.

[20] *Id.* at 31,607.

[21] *Id.*

[22] *Id.*

[23] *See* Energy Information Administration, Retail Unbundling—U.S. Summary (2005), *http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html.*

[24] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[25] Order No. 2000 at 31,015.

[26] *Id.* at 30,993.

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

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

directed the Commission to encourage the deployment of advanced technologies.[29] Congress further directed the Commission to ''exercise its authority'' under EPAct 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] EPAct 2005 also authorized the Commission to require unregulated transmitting utilities (except for certain small entities) 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 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, 2005[36] 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 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.

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 proposed a number of reforms to the *pro forma* OATT to address the opportunities and incentives transmission providers have to unduly discriminate.

Comments

27. Many commenters agree with the Commission that reforms to the *pro forma* OATT are needed because there continue to be both the opportunity and incentive for transmission providers to engage in undue discrimination.[42]

28. Several commenters offered examples of their experiences with transmission providers, where they believe transmission providers have acted in an unduly discriminatory

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

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

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

[33] EPAct 2005 sec. 1234 (to be codified at 42 U.S.C. 16432); EPAct 2005 sec. 1298 (to be codified at section 223 of the FPA, 16 U.S.C. 824w). EPAct 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] EPAct 2005 sec. 1281 (to be codified at section 220 of the FPA, 16 U.S.C. 824t).

[35] EPAct 2005 sec. 1284(d) (to be codified at section 316 of the FPA, 16 U.S.C. 825o); EPAct 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.*

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

[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.

[42] *E.g.*, APPA, EPSA, East Texas Cooperatives, Fayetteville, NRG, Occidental, TAPS, TDU Systems, Williams, Entegra Reply, and NRECA Reply.

fashion.[43] Constellation claims that on multiple occasions it has been denied a transmission request when the transmission provider's OASIS indicates that ATC is available, but Constellation had no effective and timely way to challenge that determination because of the ATC ''black box.'' Constellation states that given that its needs for transmission service are often near-term or immediate—*e.g.*, to facilitate a load-serving obligation or wholesale transaction that must be consummated quickly—seeking redress at the Commission for improperly denied service generally is not time- or cost-effective. Instead, Constellation asserts, it is often forced to accept the determination of the transmission provider that ATC is not available (even though its OASIS may indicate otherwise) and seek alternate transmission paths and/or products to consummate its transaction.

29. Powerex also describes instances where a transmission provider has granted short-term firm point-to-point transmission service requests to transmission customers who have been allowed to remain in the queue, even when zero ATC is posted, in the hopes that a transmission provider's OASIS site wrongly indicates zero ATC or will soon be updated. Powerex asserts that such practices clog the short-term point-to-point transmission queue with multiple requests and result in duplicative requests for service that reflect customers' attempts to secure service, rather than the actual quantity of service needed. Moreover, Powerex argues, transmission provider discretion in this area and the lack of transparency raise customer concerns about preferential treatment.

30. Occidental claims that it has first-hand experience with a vertically integrated transmission provider that, despite having an OATT, appears to have persistently used its transmission system to preferentially benefit its merchant function. Similarly, Williams alleges 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.

31. Other commenters, however, argue that the Commission's proposed reforms are based on unsupported allegations of undue discrimination. EEI maintains that any opportunities to engage in undue discrimination have been largely mitigated by current regulatory policies and changes in the industry. EEI explains that, unlike the situation that existed when the Commission enacted Order No. 888, much of the country's transmission facilities are now under the control of RTOs and ISOs. In addition, EEI states, other transmission providers have transferred (or are in the process of transferring) the administration of their OATTs and OASIS functions to independent transmission service coordinators. Even among the transmission providers who have taken neither of those steps, EEI argues that the open access requirements of Order No. 888 and the Standards of Conduct of Order Nos. 889 and 2004 have largely eliminated the ability of transmission providers to engage in undue discrimination in the provision of transmission service.[44] In addition, EEI states, the Commission's expanded civil penalty authority added to the FPA by EPAct 2005 gives the Commission a powerful tool that will further eliminate any remaining incentive of transmission providers to engage in undue discrimination in the provision of transmission service. Therefore, EEI asserts, any modifications to the OATT should be narrowly tailored to address the *perceptions* of residual undue discrimination. To the extent that such perceptions exist, however, Community Power Alliance states that, in the absence of concrete record evidence, they are just that—perceptions.

32. Although Duke strongly supports, as a policy matter, OATT reforms that will eliminate the perception that undue discrimination is possible and/or likely, Duke argues that the FPA does not provide the Commission the authority to remedy mere ''opportunities'' to discriminate. Duke states that, in some cases, the Commission is attempting to remedy an opportunity for undue discrimination that does not exist or is proposing to impose a remedy that does not actually remedy the perceived opportunity. Duke notes, however, that some OATT terms and conditions are subject to multiple interpretations and argues that the Commission can, and should, justify the OATT reforms proposed in the NOPR as reforms needed to provide clarity to existing policies.

33. With regard to specific allegations made by commenters, several transmission providers respond that the examples given by transmission customers do not illustrate instances of undue discrimination. Rather, they assert, these examples demonstrate the transmission customers' lack of understanding of the OATT requirements, and the data available on OASIS.[45]

34. New Mexico Attorney General argues that the traditional State-regulated, vertically-integrated cost-of-service world is not in need of reform. Contrary to the ''conspiracy theorists'' who argue that utilities have an incentive to engage in undue discrimination and preference in transmission services, New Mexico Attorney General asserts that utilities have an incentive to maximize throughput and revenue between State-level rate cases because incremental transmission revenue is not deducted from the State-jurisdictional retail revenues between rate cases. Similarly, Southern, in its reply comments, asserts that broad claims of undue discrimination fail to take into consideration that vertically-integrated utilities have more of an incentive to act appropriately than do independent utilities because the former have more to lose (*e.g.*, loss of market-based rates, state prudence reviews of costs, *etc.*) if they are found to have engaged in wrong-doing. Southern states that any OATT revisions ultimately adopted by the Commission must be reasonably tailored to address an identified problem or to provide a specific improvement.

35. Other commenters argue that the Commission's focus should be on transmission providers in non-organized markets, arguing that remaining concerns about undue discrimination have already been addressed in the world of ISOs and RTOs.[46] According to ISO/RTO Council, this proceeding provides an opportunity for the Commission to harmonize the worlds of organized and non-organized markets in a manner that encourages competition, promotes non-discriminatory access, and maximizes the flow of electricity across various ISO/RTO and non-ISO/RTO regions. ISO/RTO Council states that, in the existing regulatory environment, a utility that is not a member of an ISO or RTO can sell into, or purchase from, an ISO or RTO market even though the non-ISO/RTO utility operates under tariff rules that are less open and transparent, particularly in terms of access to generation resources and pricing/system information, than their competitors that belong to an ISO or RTO. Such asymmetry, ISO/RTO Council argues, operates as an

[43] *See, e.g.*, Dow, Fayetteville, Occidental, and Williams.

[44] *See also* Southern Reply.

[45] *See, e.g.*, Entergy Reply, Progress Energy Reply, and Southern Reply.

[46] *E.g.*, Indicated New York Transmission Owners, ISO/RTO Council, and Northeast Utilities.

impediment to fair and non-discriminatory transmission access and management of grid congestion.

36. ISO/RTO Council states that its members do not seek to impose their market designs on the rest of the nation. At the same time, ISO/RTO Council argues that meaningful reform should ensure a level of transparency (of both price and the dispatch utilized by non-ISO/RTO vertically-integrated entities) in regions without an ISO or RTO that can assist the flow of electricity and enhance reliability and planning in both ISO/RTO and non-ISO/RTO regions.

37. Exelon urges the Commission to hold the transmission providers outside ISOs or RTOs to the same standard of non-discrimination that exists within those organizations. Further, MISO/PJM States argue that in order to achieve some level of independence in non-RTO regions, non-independent transmission providers should be encouraged to turn over operational control of their transmission systems to an independent coordinator of transmission whose functions would include security coordination, determination of ATC, granting of transmission service and oversight for transmission planning.

38. Finally, EPSA suggests that the Commission establish a one-year review period for the reformed *pro forma* OATT. EPSA urges the Commission to revisit this Final Rule after one year of operation under the reformed *pro forma* OATT to ensure that the revisions adopted here do, in fact, protect against non-discriminatory or preferential behavior by transmission providers. NRECA responds that, after this comprehensive rulemaking process, there is simply no need for another major look at the OATT in one year. Moreover, NRECA states, one year is likely too short a period for the Commission and industry participants to fully appreciate all of the consequences of those elements of OATT reform resulting from this proceeding. At the same time, NRECA agrees that the Commission should carefully monitor implementation of the reformed OATT. This monitoring, NRECA states, must be an ongoing process and cannot wait a year to begin.

Commission Determination

39. The Commission concludes that reforms are needed to address deficiencies in the *pro forma* OATT that have become apparent since 1996, by limiting remaining opportunities for undue discrimination. As the Commission found in Order No. 888, it 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 to themselves.[47] Such an incentive can lead to unduly discriminatory behavior against third parties, particularly if public utilities have unnecessarily broad discretion in the application of their tariffs. This discretion also can create problems for transmission providers seeking to comply with our regulations in good faith because so many issues are left for their interpretation, thereby increasing the possibility of disputes with transmission customers and enforcement actions by the Commission.[48] Transmission customers also have found ways to use the tariffs to their own advantage, particularly in the scheduling and queuing processes.[49]

40. As some commenters note, opportunities for undue discrimination persist, particularly in areas where the *pro forma OATT* leaves the transmission provider with substantial discretion. The Commission has a responsibility under section 206 of the FPA to remedy undue discrimination. Indeed, the court concluded in *Associated Gas Distributors* v. *FERC,*[50] that, like the Natural Gas Act,[51] the FPA ''fairly bristles'' with concern over undue discrimination. Based on *AGD*, the Commission determined in Order No. 888 that:

> The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. * * * *AGD* demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination.

Order No. 888 at 31,669. Through this Final Rule, the Commission exercises that remedial authority again to limit further opportunities for undue discrimination, by minimizing areas of discretion, addressing ambiguities and clarifying various aspects of the *pro forma OATT*.

41. We disagree with commenters who assert that the Commission is relying on unsubstantiated allegations of discriminatory conduct to justify OATT reform. The courts have made clear that the Commission need not make specific factual findings of discrimination in order to promulgate a generic rule to eliminate undue discrimination.[52] In *AGD*, the court explained that the promulgation of generic rate criteria involves the determination of policy goals and the selection of the means to achieve them and that courts do not insist on empirical data for every proposition upon which the selection depends: ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.'' [53] During this multi-year proceeding, the Commission has received many comments arguing that commenters have either experienced or perceived that they have experienced unduly discriminatory conduct by transmission providers. Even transmission providers have acknowledged that there is a continuing perception that there is the opportunity for them to unduly discriminate against their competitors and, accordingly, they state their support for our reform effort.[54] Moreover, it is undisputed that the existing *pro forma* OATT provides wide discretion in implementing some of its basic requirements, such as the assessment of whether sufficient ATC exists to grant third party access to the grid and the manner in which new facilities are planned to satisfy third party needs. This wide discretion, when coupled with a transmission provider's incentive to discriminate, creates opportunities for discrimination under the *pro forma* OATT. We have an obligation under section 206 to remedy that discrimination.

42. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 888, opportunities to engage in undue discrimination can and will persist unless the existing *pro forma* OATT is reformed. We therefore exercise our broad remedial authority today to limit these remaining

[47] Order No. 888 at 31,682.

[48] *See, e.g.*, Order No. 2003 at P 11–12.

[49] *See, e.g.*, Potomac Economics, Ltd., *2004 State of the Market Report: Midwest ISO* at 30–31, 34–35 (Jun. 2005), *http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-7bf20a48324a/2004%20MISO%20SOM%20Report.pdf?action=download&_property=Attachment* (explaining that the queuing process, by giving customers the opportunity to submit multiple requests for service, provides a low- or no-cost option that restricts other customers' access to congested interfaces, and the scheduling process, by allowing customers to leave transmission requests unconfirmed, provides a free option that may invite hoarding or result in underutilized capacity).

[50] 824 F.2d 981 (D.C. Cir. 1987) (*AGD*).

[51] 15 U.S.C. 717.

[52] *TAPS* v. *FERC*, 225 F.3d at 667, 688; *National Fuel Gas Supply Corp.* v. *FERC*, 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*).

[53] 824 F.2d at 1008.

[54] *See, e.g.*, Duke and EEI.

opportunities for undue discrimination. The Commission concludes that any additional costs incurred by transmission providers to implement the reforms required in this Final Rule are fully justified by the need to ensure open, transparent and non-discriminatory access to transmission service. We also believe it is appropriate to adopt these reforms by rulemaking, rather than rely on complaints 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. EPSA agrees that greater transparency will help enable market participants and the Commission to monitor and audit the behavior of transmission providers. EPSA states that the several ''black boxes'' shielding discriminatory transmission service over the past ten years must be opened. However, EPSA 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

[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).

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 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 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 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 transmission providers have filed only summary explanations of their ATC methodologies in Attachment C to their OATTs.

63. In the NOPR, the Commission noted that, although the industry has sought to pursue greater consistency in ATC calculations through existing NERC processes, these efforts to date have been largely unsuccessful. The Commission expressed its preliminary determination that the lack of a consistent, industry-wide methodology for calculating ATC gives transmission providers the ability and the opportunity to unduly discriminate against third parties. The Commission therefore proposed a number of reforms to the process of calculating ATC to provide clarity and transparency to users of the grid.

Comments

64. As discussed further in section V.A below, most commenters support the Commission's goal of requiring greater consistency in the manner in which ATC is calculated and additional transparency of ATC calculations. Commenters generally favor the Commission's proposal to increase consistency in the calculation of ATC, including consistent definitions of its components, data inputs, modeling assumptions, and data exchange and coordination protocols. For example, Exelon argues that each ATC component should be used in the same manner for all purposes (*e.g.*, granting transmission service to third parties or for the transmission provider's own network load). Some commenters assert that industry-wide standardization of ATC calculation might not be possible and that the Commission should consider interconnection-wide, regional or even sub-regional standardization. Others suggest allowing flexibility in order to capture differences in system operation, usage, market operations and topology.

65. At the technical conference organized in this proceeding on October 12, 2006 (October 12 Technical Conference), the entire panel agreed that definitions must be consistent and a panelist representing Constellation

[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).

[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 http://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 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*.

[63] Order No. 888 at 31,794 n.610.

asserted that broad differences in the core definitions of the ATC calculation are neither rational nor explainable.[64] NERC, however, recognized that the goal of achieving consistency may not mean that a single ATC methodology is required.[65] NERC explained that consistency can be achieved with a limited number of methodologies if the requirements of those methodologies are properly coordinated and communicated.

66. Numerous commenters support the Commission's proposals to increase transparency in the manner in which transmission providers derive ATC, including greater OASIS posting. Commenters opposing the transparency-related reforms focus on the Commission's proposal to require the posting of narratives on OASIS explaining reasons for changes in monthly and yearly ATC values on constrained paths. They argue that such a requirement would be too burdensome and would not provide customers with any significant new information.

67. Several commenters believe that making substantial ATC calculation and modeling data transparent will compromise Critical Energy Infrastructure Information (CEII) but provide suggestions for resolving the issue. Others express concern that the data required for posting on OASIS is not CEII but commercially sensitive. Finally, commenters provide suggestions regarding the requirement to post metrics on OASIS related to the provision of transmission service under the *pro forma* OATT, including various additional metrics the Commission should consider. Others state that this information is already available on OASIS.

Commission Determination

68. We find that the lack of a consistent and transparent methodology for calculating ATC gives transmission providers the ability and opportunity to unduly discriminate in the provision of open access transmission service. There are few clear rules respecting ATC calculation, and transmission providers retain unnecessarily broad discretion in this area. This resulting discretion is a significant problem because calculation of ATC, which varies greatly depending on the criteria and assumptions used, may allow the transmission provider to discriminate in subtle ways against its competitors. On systems where transmission capacity is congested, this lack of consistency, coupled with a lack of transparency, is of heightened importance and has led to recurring disputes over whether the transmission provider is exercising its discretion to discriminate against its competitors. This discretion also hampers the detection of undue discrimination and, thereby, undermines the Commission's ability to enforce the general requirement in Order No. 888 that transmission service be provided on a not unduly discriminatory basis.

69. As discussed more fully below in section V.AIII.D, this Final Rule adopts a number of reforms that address the potential for remaining undue discrimination in the determination of ATC by requiring consistency in how ATC is evaluated, as well as providing greater transparency about how a transmission provider calculates and allocates ATC.

E. Discriminatory Pricing of Imbalances

70. Order No. 888 focused primarily on the adoption of non-rate terms and conditions of service, rather than instituting broad reform of the Commission's transmission pricing policies. Consistent with this focus, the Commission did not propose broad transmission pricing reform in the NOPR, but rather focused on instances where current pricing practices under the *pro forma* OATT may no longer be sufficient to remedy undue discrimination or ensure just and reasonable rates. One significant reform proposed in the NOPR related to charges for imbalance energy. The Commission preliminarily found that the existing policies provide wide discretion in the development of these charges and hence the potential for undue discrimination. The Commission therefore proposed certain principles to remedy that potential and sought comment on whether a specific imbalance pricing method would be appropriate.

Comments

71. In general, transmission customers complain about the level and scope of energy and generator imbalance charges that are levied under the *pro forma* OATT and under individual interconnection agreements.[66] Customers complain that energy imbalance charges are excessive and not related to the actual costs incurred by transmission providers. They also argue that the inconsistency between these charges in different control areas is unnecessary, and that other means of compensating the transmission provider, such as return-in-kind, should be considered. Generators likewise complain that generator imbalance charges are excessive, that transmission providers refuse to credit generators with the revenues resulting from imbalance penalties that are collected, and that transmission providers prevent unaffiliated generators from purchasing or self-supplying generator imbalance services. In addition, owners of intermittent resources complain that generator imbalance charges, which are imposed to provide an incentive for generators to schedule accurately, are inappropriate given their lack of control and ability to cure deviations.

Commission Determination

72. The Commission agrees that imbalance charges should provide appropriate incentives to keep schedules accurate without being excessive. We also find that consistency in imbalance charges, both between and among energy and generator imbalances, is preferable to the wide variety of imbalance provisions in place today. All imbalances have the same net effect on the transmission system in that they require other generation to be ramped up or down to compensate for the imbalance. As such, the Commission adopts two *pro forma* OATT provisions (Schedule 4 for energy imbalances and Schedule 9 for generator imbalances) based on a tiered structure similar to the imbalance provision used by Bonneville, as described further below. Such an approach recognizes the link between escalating deviations and potential reliability impacts on the system while keeping imbalance charges closely related to incremental costs. The Commission finds, however, that intermittent resources should be exempt from the highest-tier deviation band. We also require transmission providers to credit to all non-offending transmission customers the revenues they collect in excess of incremental costs.

F. Redispatch/Conditional Firm

73. In the NOPR, the Commission examined whether existing methods for evaluating requests for long-term firm point-to-point service continue to be just and reasonable. 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

[64] Transcript of October 12 Technical Conference at 149–50, *available at* Preventing Undue Discrimination and Preference in Transmission Service, Technical Conference (Docket No. RM05–25–000).

[65] *Id.* at 125–50.

[66] Energy imbalance charges, including penalties on some systems, are imposed on a transmission customer when the amount of energy scheduled for delivery to the transmission grid does not equal the amount of energy withdrawn by that customer. Generator imbalance charges are levied on generators for deviations between the amount of energy they schedule and the amount they actually deliver to the grid.

deliverable during a few hours of the year. For transmission customers, however, the transmission provider evaluates whether service can be granted in every hour of the year that is modeled and, if not, it informs the customer that service cannot be provided out of existing transfer capability. Only if the transmission customer agrees to pay for facilities studies does the transmission provider evaluate redispatch options, including whether they are less expensive than the upgrade costs. The Commission therefore proposed to reform the existing *pro forma* OATT planning redispatch [67] obligation, or, in the alternative, to add a conditional firm service to the *pro forma* OATT. As proposed by the Commission, conditional firm would have been a long-term service allowing the transmission provider to give a lower curtailment priority than firm to the transmission customer during a pre-specified number of hours.

Comments

74. Some commenters support the inclusion of both a modified planning redispatch obligation and a conditional firm service in the *pro forma* OATT, stating that both are required to remedy undue discrimination and provide for comparable transmission service. These commenters urge the Commission to require transmission providers to offer planning redispatch and conditional firm service and allow customers to choose the option that best suits their physical, commercial and economic circumstances.

75. Others opine that conditional firm service may be simpler and less costly to implement. These commenters prefer the development of conditional firm service over the modifications to the planning redispatch service because of the complexities surrounding redispatch costs and protocols. For example, Entergy believes conditional firm service can provide benefits to transmission customers without unfairly socializing costs to native load and network customers of the transmission provider.

76. On the other hand, many commenters argue that the Commission should not require either option because the services are unnecessary, operationally unworkable, and legally unjustified, or because they would harm reliability and the quality of existing network service and provide disincentives for transmission investment. Several commenters state that these services would make curtailments of existing firm service more likely and limit opportunities for use of secondary network service, thereby harming native load protections and reducing reliability, contrary to FPA sections 215 and 217 respectively. While it recognizes that conditional firm service has been successful in parts of the Western Interconnection, NRECA contends that a mandate would undermine responsible planning and expansion of the transmission grid by harnessing the transmission provider's planning and dispatch functions to frame elaborate service conditions for conditional firm service.

77. Several commenters argue that, if the services are required, the Commission should ensure that reliability is not adversely affected. Others urge the Commission to make the new services an interim option until transmission upgrades are in place to provide firm service. Some commenters believe planning redispatch and conditional firm customers should bear the actual costs of the services received, including costs associated with system operational changes needed to accommodate the services. A few commenters believe that the Commission should allow for regional differences in development of the new services.

Commission Determination

78. The Commission believes it is necessary to modify the manner in which transmission providers assess point-to-point service requests to eliminate the potential for undue discrimination in transmission service. We find that both techniques—planning redispatch and conditional firm service—are currently used under certain circumstances by transmission providers to serve native load and, therefore, that transmission customers should have comparable services in order to avoid undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. We expect that both options will help integrate new generation more quickly. This can be particularly beneficial to renewable generation resources, such as wind, that can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run.

G. EPAct 2005 Emphasized Certain Policies and Priorities for the Commission

79. Finally, we note that the reforms adopted in this proceeding are consistent with the policies and priorities embodied in EPAct 2005, in which Congress emphasized many of the same principles reflected in this Final Rule. First, in EPAct 2005, Congress placed special emphasis on the development of transmission infrastructure. Congress required the Commission to adopt a rule establishing incentive-based rates for new transmission infrastructure investment. The stated purpose of new FPA section 219 is to benefit ''consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.'' [68] Among other steps, FPA section 219 requires the Commission to ''(1) Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; (2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); [and] (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities.'' [69] In addition, Congress directed the Commission to encourage the deployment of advanced transmission technologies.[70] Congress also gave the Commission certain ''backstop'' transmission siting authority, and authorized the creation of interstate compacts establishing transmission siting agencies.[71] Finally, the Commission was directed to exercise its authority under EPAct 2005 ''in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the

[67] Although *pro forma* OATT section 13.5 refers to ''redispatch,'' we refer to it here as ''planning redispatch'' to distinguish it from the reliability redispatch provisions in the network integration transmission service sections of the *pro forma* OATT. *See infra* notes 552 and 557.

[68] EPAct 2005 sec. 1241 (to be codified at section 219 of the FPA, 16 U.S.C. 824s). The Commission has issued a Final Rule implementing such an incentive rate program. *See* Order Nos. 679 and 679–A.

[69] FPA Sec. 219(b)(1).

[70] EPAct 2005 sec. 1223 (to be codified at 42 U.S.C. 16442).

[71] EPAct 2005 sec. 1221(a) (to be codified at section 216 of the FPA, 16 U.S.C. 824p). The Commission implemented new regulations in accordance with this section to establish filing requirements and procedures for entities seeking to construct electric transmission facilities in Order No. 689.

service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights * * * on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.'' [72] Although these provisions have been, or will be, addressed primarily in other proceedings, we conclude that the Final Rule is consistent with these provisions because it supports improvements in infrastructure by reforming the transmission planning process to ensure that it is open, transparent and nondiscriminatory.

80. Second, Congress emphasized the need for greater transparency in electricity markets, including transmission service. EPAct 2005 added section 220 to the FPA, which requires 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 [that market], fair competition, and the protection of consumers.'' [73] The Commission was authorized to ''prescribe such rules as the Commission determines necessary and appropriate to carry out the purposes of'' FPA section 220. Those rules ''shall provide for the dissemination, on a timely basis, of information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public.'' This Final Rule similarly will promote greater transparency in the provision of transmission service in many important areas, including ATC calculation and transmission planning.

81. Finally, Congress emphasized compliance with the Commission's regulations, increasing the civil and criminal penalties for violations of Commission-administered statutes and regulations.[74] This new authority buttresses the Commission's efforts to enforce public utility OATTs and the regulations requiring transmission information to be 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 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.

[72] EPAct 2005 sec. 1233(a) (to be codified at section 217(b)(4) of the FPA, 16 U.S.C. 824q). The Commission implemented FPA section 217(b)(4) in *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 71 FR 43564 (Aug. 1, 2006), FERC Stats. & Regs. ¶ 31,226 (2006), *order on reh'g*, Order No. 681–A, 117 FERC ¶ 61,201 (2006), *reh'g pending*.

[73] EPAct 2005 sec. 1281 (to be codified at 16 U.S.C. 824t).

[74] EPAct 2005 sec. 1284(e)(1) (to be codified at section 316(A) of the FPA, 16 U.S.C. 825o–1).

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

• *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 EPAct 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 distribution facilities in situations involving unbundled wholesale wheeling and unbundled retail wheeling,[77] the Commission stated that it generally would defer to determinations by State regulatory authorities concerning where to draw the jurisdictional line under that test.[78] The Commission declined to assert jurisdiction over bundled retail transmission, reasoning that ''when transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail.'' [79] The U.S. Supreme Court affirmed the Commission's decision to assert jurisdiction over unbundled but not bundled retail transmission, finding that the Commission made a statutorily permissible choice.[80] In the NOPR, the Commission proposed to retain the jurisdictional divide established in Order No. 888.

Comments

93. Several commenters support the Commission's proposal to retain the existing jurisdictional divide.[81] Though APPA concludes that the most politic course at this juncture is to leave the current jurisdictional boundaries in place and develop cooperative mechanisms in each region to coordinate Federal policy implementation with the relevant State regulators, APPA notes that there is disagreement among its members about whether the current jurisdictional lines are properly drawn. APPA explains that a substantial number of its members believe that all interstate transmission services (both retail and wholesale) should be provided under one consistent set of tariff terms and conditions. Other APPA members, however, believe that the Commission made the proper jurisdictional call in Order No. 888. NARUC urges the Commission to clarify that its planning proposals will not reopen or attempt to change the jurisdictional split over transmission facilities delineated in Order No. 888.

Commission Determination

94. The Commission will retain the existing jurisdictional divide that was established in Order No. 888, which has been affirmed by the U.S. Supreme Court and accepted by the industry and State regulatory authorities.[82] We also reiterate our recognition of the need for heightened cooperation between Federal and State regulators in areas where there are overlapping Federal and State policy concerns. As explained in greater detail in the planning section below, and in response to NARUC's concern, the planning reforms adopted in the Final Rule contemplate coordinated and open transmission planning, but do not reopen or otherwise change the existing jurisdictional divide for transmission facilities.

2. Native Load Protection

95. In Order No. 888, the Commission did not require transmission providers to unbundle transmission service to their retail native load. The Commission also did not require that bundled retail service be taken under the terms of the *pro forma* OATT.[83] Moreover, the Commission allowed a transmission provider to reserve, in its calculation of ATC, transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon.[84] Order No. 888 also granted a rollover right to existing firm service customers,[85] but allowed transmission providers to restrict that rollover right if the capacity was reasonably forecasted as needed to serve native load customers, as long as that restriction was set forth in the customer's initial service contract.[86]

96. Congress, in section 1233 of EPAct 2005, added section 217 to the FPA, entitled ''Native Load Service Obligation,'' which addresses transmission rights held by load-serving entities (LSEs). FPA section 217 allows LSEs to use their own and contracted-for transmission capacity to deliver energy as required to meet their service obligations, without being subject to charges of unlawful discrimination. The provision makes clear, however, that this requirement does not abrogate any contract or service agreement for firm transmission service or rights in effect as of the date of enactment of EPAct 2005.[87] In the NOPR, the Commission concluded that the protection of native load embodied in Order No. 888 is consistent with FPA section 217, and reaffirmed its commitment to the protection of native load.

Comments

97. Several commenters agree with the Commission's preliminary conclusion that the protection of native load embodied in Order No. 888 is consistent with FPA section 217 and support the Commission's continued commitment to the protection of native load.[88] While APPA [89] and TAPS generally agree with the Commission that the overall OATT regime is consistent with section 217, they urge the Commission to maintain and reinforce the comparability requirement. APPA urges the Commission to broaden its preliminary conclusion in the NOPR and conclude instead that the protection of native load *and* the provision of fully comparable transmission service to other LSEs with long-term service obligations, as embodied in Order No. 888, are consistent with FPA section 217. TAPS also supports the Commission's reading of FPA section 217 as consistent with the Order No. 888 *pro forma* OATT's ''native load'' priority, recognizing that FPA section 217 reinforces the OATT's commitment to comparable treatment of all LSEs—*e.g.*, transmission providers and network customers.

98. Other commenters dispute the Commission's preliminary conclusion that the native load protection embodied in Order No. 888 is consistent with FPA section 217.[90] Many commenters argue that FPA section 217 protects all load, not just native load.[91] Constellation states that the Commission must recognize that there are other market participants besides the transmission providers themselves that are LSEs under FPA section 217. Under the definition of LSEs in FPA section

[76] Order No. 888 at 31,781.

[77] *Id.* at 31,771 (setting forth the seven-factor test).

[78] *Id.* at 31,781.

[79] *Id.*

[80] *See New York* v. *FERC*, 535 U.S. at 28.

[81] *E.g.*, Ameren, APPA, North Carolina Commission Reply, PNM–TNMP, and Southern.

[82] *See New York* v. *FERC*, 535 U.S. at 28.

[83] Order No. 888 at 31,745.

[84] *Id.* at 31,694.

[85] *Id.; see pro forma* OATT section 2.2.

[86] Order No. 888–A at 30,198.

[87] 16 U.S.C. 217(f).

[88] *E.g.*, Ameren, E.ON, Tacoma, Arkansas Commission, EPSA, Southern, and TAPS.

[89] APPA argues that the proposed definition of native load customers in section 1.21 is not technically consistent with FPA section 217 because FPA section 217 does not distinguish among the types of power supply arrangements that an LSE must have to enjoy the protection of FPA section 217. Nevertheless, APPA states that it would not be fruitful to reopen the entire OATT framework to address this technical (but very important) definitional difference.

[90] *E.g.*, Arkansas Municipal, Constellation, Duke, Salt River, and South Carolina E&G.

[91] *E.g.*, Constellation, EPSA, and South Carolina E&G.

217, EPSA argues that many entities other than traditional, vertically-integrated utilities are in the business of serving load. The statute, EPSA asserts, applies to any native load service obligation, whether that obligation is served by a competitive supplier, an affiliate of the transmission provider, or by the transmission provider itself. Salt River contends that FPA section 217 is self-implementing, though it urges the Commission to act to remove impediments to the full exercise of rights granted to LSEs.

99. Constellation argues that the Commission should require native load and OATT customers to take service under the same terms and conditions because experience has proven that discrimination has occurred as a result of having two different sets of rules applicable to transmission customers. EPSA urges the Commission to further clarify that the transmission provider has an affirmative obligation to serve native load in a non-discriminatory manner. According to EPSA, section 217 supports the Commission's paramount statutory mission of ensuring non-discrimination and makes clear that a transmission provider, when utilizing transmission capacity or rights reserved to serve native load, must ''put its blinders on'' to ensure that the load's needs are being met in the most economical way available, whether that decision means the deployment of its own affiliated generation, or the deployment of available non-utility alternatives.

100. Arkansas Municipal asserts that FPA section 217 recognizes the need to give priority to LSEs in certain situations, such as when the transmission grid may be constrained and one group of customers may be denied service at the expense of other customers. Arkansas Municipal states that a priority list could be instituted in this reform proceeding that places LSEs at the top of the list in competing requests for transmission service when not all requests could be granted or honored by the transmission provider.

101. New Mexico Attorney General argues that native load is fundamentally different than merchant load and therefore, in the planning process, the needs of merchants should not be treated comparably with the needs of New Mexico utilities' native loads. New Mexico Attorney General asserts that New Mexico utilities have a statutory obligation to serve retail load while merchants are free to come and go with cycles inherent in wholesale markets. According to New Mexico Attorney General, the transmission requirements of the utilities' native loads amount to an ongoing long-term firm contract, while the transmission needs of merchants are, by comparison, short-term and speculative.

102. Several commenters urge the Commission to revisit various aspects of the reforms proposed in the NOPR in order to enhance the protection of native load. For example, some commenters urge the Commission to modify the rollover proposal in the NOPR. Salt River argues that the Commission's regulations must include a clear provision for a transmission owner anticipating, or unexpectedly facing, load growth to recapture capacity temporarily made available to the wholesale market. Arkansas Commission disagrees with the Commission's proposal to require a transmission provider to compete for transmission capacity rather than reclaim it through its rights to reserve capacity for future load growth. The proposal is inequitable, Arkansas Commission argues, because native load customers have historically paid for most of the transmission providers' assets and will continue to do so in the future. Because of this, Arkansas Commission asserts, native load customers should be given preference in the reservation of transmission capacity. In response to Arkansas Commission's position, MDEA urges the Commission to make clear, consistent with the comparability principle adopted in Order No. 888 and reaffirmed in the NOPR, and with FPA section 217, that any reservation of rights or preference available to a transmission provider's native load customers must be available to network customer loads as well. South Carolina E&G argues that the Commission's interpretation of ''reasonably forecasted'' capacity under section 2.2 of the *pro forma* OATT has been effectively impossible to meet and, therefore, the Commission should now provide clear standards for evaluation of native load protecting rollover restrictions. A clear standard, South Carolina E&G states, would have the Commission consider rollover restrictions in light of a utility's transmission planning process. On reply, Progress Energy supports South Carolina E&G's comments. Progress Energy urges the Commission to revisit the rollover rights policy to develop a policy by which an LSE may be assured of future transmission service for reasonably forecasted native load growth.

103. South Carolina E&G also asks the Commission to revise section 13.6 of the *pro forma* OATT, regarding curtailment of firm point-to-point transmission service. South Carolina E&G urges the Commission to comply with the mandate of *Northern States Power Co.* v. *FERC*,[92] which South Carolina E&G asserts held that the Commission had exceeded its authority in rejecting a vertically-integrated transmission provider's proposal to modify section 13.6 of the OATT to give a higher curtailment priority to native load. According to South Carolina E&G, the Commission has responded by applying the court's decision narrowly, but FPA section 217 requires the Commission to change that position and recognize the primacy of service to native load in section 13.6 of the OATT. In its reply comments, Progress Energy supports the comments of South Carolina E&G and states that the Commission must affirmatively recognize the priority of service to LSEs in the application of the curtailment priorities in section 13.6 of the OATT.

104. Duke argues that several of the Commission's proposed reforms—such as hourly firm service, redispatch, and conditional firm service—actually reduce the protection afforded native/network load. Salt River suggests that the Commission should modify its ATC proposal to bring the Commission's native load priority policies in line with FPA section 217. Salt River asserts that, in calculating ATC, the transmission provider must be able to exercise reasonable professional judgment as to the amount of transmission that must be reserved to meet native load service obligations; the Commission should not get into the business of dictating forecasting methodology. Salt River proposes that a native load forecast that is used by an LSE as the basis for committing capital for generation expansion or procurement should be presumed to be valid for purposes of establishing available capacity. EPSA, however, argues that, unless and until the Commission mandates a hard and enforceable definition of ATC, transmission-owning utilities that also own affiliated generation will continue to hide behind the native load service obligation as an excuse for being unable to find ATC for any but self-serving purposes.

105. EPSA also argues that the Commission must ensure that transmission owners' planning accommodates all supply options. EPSA urges the Commission to clarify that transmission capacity reserved for native load is to be made available (including for study and other purposes) to competitive suppliers who wish to

[92] 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied sub nom. Enron Power Marketing, Inc.* v. *Northern States Power Co.*, 528 U.S. 1182 (2000).

serve native load as allowed by State law. According to EPSA, all generation assets ultimately serve load and the *pro forma* OATT should be clarified to ensure that the transmission system is available on a non-discriminatory basis now and in the future to ensure that load is optimally served—regardless of which generation resources are serving that load. In its reply comments, EPSA also challenges the initial comments of New Mexico Attorney General, which EPSA argues incorrectly interpret FPA section 217 as drawing a distinction between the types of generation that serve load. EPSA argues that the statute protects the customer load that all suppliers would seek to serve regardless of the source.

106. APPA agrees with the Commission's response in the NOPR to Metropolitan Water District that the specific issues related to an RTO's provision of long-term transmission rights are better left to the rulemaking in Docket Nos. RM06–8–000 and AD05–7–000, and the proceedings in each RTO region to implement the Final Rule issued in those dockets on July 20, 2006. APPA notes, however, that the Commission has not proposed in this docket to exempt RTOs from the provisions of the NOPR. Rather, APPA notes, departures from the *pro forma* OATT, including departures in RTO OATTs, must be justified under the ''consistent with or superior to'' standard. APPA argues that the Commission should apply this standard to long-term transmission rights, as well as to the other terms and conditions of OATT transmission service that RTOs provide.

Commission Determination

107. In Order No. 888, the Commission gave public utilities the right to reserve existing transmission capacity needed for native load growth reasonably forecasted within the utility's current planning horizon. The Commission also allowed transmission providers to restrict rollover rights based on reasonably forecasted need at the time the contract is executed. We continue to believe these protections for native load are appropriate and do not eliminate them in this Final Rule, as suggested by some commenters. We also believe that the protection of native load embodied in Order No. 888, as enhanced by the reforms adopted in this Final Rule, is consistent with FPA section 217, which protects the transmission rights of entities with service obligations to end-users or a distribution utility, to the extent required to meet their service obligations. The additional reforms proposed by commenters are not necessary at this time to remedy undue discrimination. We conclude that the native load priority established in Order No. 888 continues to strike the appropriate balance between the transmission provider's need to meet its native load obligations and the need of other entities to obtain service from the transmission provider to meet their own obligations.

108. In response to comments regarding reforms needed to ATC calculation and transmission planning to bring the native load priority policies in line with FPA section 217, we believe that the Commission's reforms in this Final Rule appropriately reflect the transmission provider's obligation to serve native load. As discussed more fully in the ATC and planning sections below, the processes we adopt herein are open, transparent and non-discriminatory and assume that the transmission provider is meeting its obligations, including its native load service obligation. We disagree with Duke's assertion that the reforms proposed in the NOPR will result in a reduction of the protection afforded native or network load. Not only have we reaffirmed the fundamental protections for native load contained in Order No. 888, but we have modified, where appropriate, the *pro forma* OATT to ensure that a transmission provider's obligations can be met consistent with maintaining the reliability to existing customers, including native load. For example, we are eliminating the current requirement to provide planning redispatch over long periods of time (*e.g.*, 10–30 years) because it is unnecessary to remedy undue discrimination and can create problems in forecasting system conditions consistent with maintaining reliability to native load customers.[93]

109. With regard to APPA's comments regarding long-term transmission rights in organized markets, we note that the Commission has issued its Final Rule in Docket Nos. RM06–8–000 and AD05–7–000.[94] As discussed more fully in the applicability section of this rulemaking, and in response to APPA's comments, we reiterate that any departures from the *pro forma* OATT proposed by an ISO or an RTO must be ''consistent with or superior to'' the *pro forma* OATT in this Final Rule.

[93] Proposals related to other reforms, such as curtailments and rollovers, are discussed in the sections below dealing with each of those issues.

[94] *See supra* note 72.

3. The Types of Transmission Services Offered

110. In Order No. 888, the Commission required all public utilities to offer, on a non-discriminatory, open-access basis, firm network service and firm and non-firm point-to-point service. In the NOPR, the Commission proposed to retain these services and did not propose to require transmission providers to adopt a network contract demand service, either as a replacement for network or point-to-point service or as a third category of service under the OATT.

Comments

111. Several commenters support the Commission's proposal to retain the current services in the *pro forma* OATT and to not adopt contract demand service.[95] While APPA supports the Commission's proposal, it states that the Commission should remain open to individual public utility transmission provider's proposals to add ''hybrid'' service to the base network and point-to-point services.

112. Other commenters, such as AMP-Ohio and Nevada Companies, argue that the Commission should require all transmission providers to offer network contract demand service. Nevada Companies argue that the Commission's network designation process can substantially interfere with State jurisdiction over resource acquisition, especially for transmission providers that are required to purchase substantial amounts of power to serve their retail customers instead of relying primarily on their own generation. Nevada Companies reason that allowing transmission providers to move to a contract demand-based network service would remove them from the dilemma of being forced to make resource procurement decisions that are inconsistent with State requirements. On reply, MidAmerican, Newmont Mining, and Utah Municipals oppose the suggestion that the contract demand service should be made a mandatory service offering in the *pro forma* OATT. In its reply comments, Newmont Mining states that, if the Commission is inclined to provide some relief to allow Nevada Companies to comply with both the *pro forma* OATT and their State-approved resource plans, that relief should come only after an investigation of how similar problems are handled on other systems and should be a narrowly and carefully monitored exception to the resource designation requirements.

[95] *E.g.*, MISO/PJM States, TVA, and Southern.

113. Alberta Intervenors argue that undue discrimination is most likely to occur in situations where there is a single or dominant network customer and that customer either has a dual mandate for serving the network customers or that customer has a ''free option'' for procuring transmission.[96] Alberta Intervenors recommend that the Commission implement standardized rules with respect to the ''free option'' concept while offering regional flexibility to ensure the objectives of open access and the absence of undue discrimination continue to be advanced. Alberta Intervenors also argue that, despite the Commission's proposal to address undue discrimination against transmission customers in attempting to redirect to new receipt and delivery points, undue discrimination remains a concern since network customers retain a flexibility of receipt and delivery points that is not granted to third party point-to-point customers. This flexibility provided to the network customer allows the use of the system for activities known as ''parking'' [97] and ''hubbing.'' [98] Alberta Intervenors urge the Commission to eliminate this unfair competitive advantage under the OATT by making a common service available to all participants rather than differing service for network customers, or alternatively, by restricting the use of point-to-point services by the network customer to exclude its use for ''parking'' and ''hubbing.''

114. MidAmerican states that in the Western Interconnection, a utility's loads are not necessarily located within a confined geographical boundary served by a single transmission owner. In these cases, MidAmerican argues, neither network nor point-to-point service under the current *pro forma* OATT is suitable to serve those loads. To remedy these shortcomings in standard OATT service, MidAmerican states that the Commission should require the incorporation of dynamic scheduling and long-term, seasonally-shaped, firm point-to-point as new service offerings under the *pro forma* OATT.

Commission Determination

115. The Commission will not alter the types of services that we required in Order No. 888. We continue to believe that network and point-to-point services are the appropriate base-line service offerings in the OATT, and we will not mandate that transmission providers adopt new service offerings such as network contract demand service. Although the Commission has accepted forms of network contract demand service proposed by individual transmission providers, and the service may provide benefits to certain customers, we do not believe the service is necessary to remedy undue discrimination. For example, the service would require a departure from full load-ratio pricing for network customers, which may not be warranted to the extent the transmission provider plans its system to serve all native load. However, while the Commission concludes that it will not require all transmission providers to offer this service, in response to the arguments raised by commenters such as AMP-Ohio and Nevada Companies, we reiterate that the Commission already has accepted forms of network contract demand service and will continue to entertain such proposals on a voluntary basis from transmission providers.

116. The Commission also is not persuaded by Alberta Intervenors' and MidAmerican's arguments in support of further alternative services under the *pro forma* OATT. As with network contract demand service, transmission providers may propose such services if appropriate for their region. We do not believe mandating that such services be provided by all transmission providers is necessary at this time to prevent undue discrimination.

4. Functional Unbundling

117. In Order No. 888, the Commission chose to mandate functional, rather than corporate (in which a public utility's transmission and generation assets would be placed in separate corporate entities), unbundling of transmission and generation services. The Commission explained that functional unbundling has three components:

1. A public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;

2. A public utility must state separate rates for wholesale generation, transmission, and ancillary services;

3. A public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[99]

118. In the years following Order No. 888, a number of public utilities nonetheless underwent corporate unbundling. Many of these entities did so as a result of State-mandated restructuring laws. Others did so for corporate or tax reasons. Some entities divested all of their generation assets to a non-affiliate, while others simply restructured internally to place the generation assets in a different corporate subsidiary than the transmission assets. There remain, however, a significant number of vertically-integrated public utilities that operate under the functional unbundling approach.

119. In the NOPR, we proposed to preserve the functional unbundling approach adopted in Order No. 888, rather than impose a corporate or structural unbundling requirement. While the Commission expressed its continued support for voluntary efforts to adopt structural changes (such as transmission-only companies, RTOs, or other reforms), the Commission found that the more intrusive and costly corporate unbundling was not necessary at this time. The Commission also declined to mandate an independent transmission coordinator for all transmission providers. Though the Commission has previously found that such entities may be appropriate in certain circumstances and we support voluntary efforts to rely on them,[100] the

[96] Alberta Intervenors assert that the purchase of point-to-point service by dominant network customers results in an equal and offsetting reduction to the network customer's network charges, resulting in a net cost of zero. They state that point-to-point service is a net cost to all competitors except the dominant network customer. Thus, they argue, a dominant network customer can buy point-to-point service for an extended period and use this service for a limited number of hours at little (or no) net cost compared to not purchasing point-to-point service for an extended period. In Alberta Intervenors' view, this ''free option'' provides network customers with a competitive advantage when reserving point-to-point service because it enables the network customers to over-consume or buy excess point-to-point service than they would if the true net cost were reflected. Alberta Intervenors contend that such over-consumption reduces access to point-to-point service for other customers.

[97] Alberta Intervenors define ''parking'' as a network customer reserving point-to-point service using a network load point of delivery to purchase energy that it intends to sell but where no buyer has been identified at the time of the reservation. The energy notionally reduces network load. Once a buyer is found, the network customer completes the sale by delivering the energy from freed-up generation at a generation point of receipt to a buyer's point of delivery.

[98] Alberta Intervenors define ''hubbing'' as a practice very similar to ''parking,'' but involving multiple buyers and sellers. The network customer can reserve point-to-point transmission to purchase energy from multiple sellers and to sell energy to multiple buyers by creating a hub within its network load. Alberta Intervenors explain that this allows the network customer to organize purchases and sales by physically matching the requirements of multiple buyers and sellers.

[99] Order No. 888 at 31,654.

[100] *See Duke Power*, 113 FERC ¶ 61,288 (2005); *MidAmerican Energy Co.*, 113 FERC ¶ 61,274 (2005); *see also Entergy Services, Inc.*, 110 FERC 61,295 (2005), *order on clarification*, 111 FERC ¶ 61,222 (2005), *order conditionally approving filing*, 115 FERC ¶ 61,095 (2006).

Commission concluded that there was not a sufficient basis for requiring them as a generic remedy for undue discrimination.

Comments

120. Commenters generally support the Commission's proposal to retain functional unbundling.[101] APPA also supports the Commission's decision not to mandate an independent transmission coordinator for all public utility transmission providers. Similarly, Tacoma supports the Commission's decision to continue to view participation in an RTO or ISO as voluntary actions. While PJM and EPSA would prefer a structural remedy, they generally support the Commission's proposal to retain functional unbundling. However, EPSA states that given the Commission's proposal to continue to rely on functional unbundling, it is critical, particularly in those areas without organized markets, that OATT rules regarding unbundled transmission service be clear, transparent, consistent, and rigorously enforced. APPA states that it will be vital to obtain the cooperation of State regulators in each region where the OATT reforms will be implemented to ensure that the current functional unbundling regime in fact is sufficient to do the job.

121. E.ON and TVA express concern that the Commission may yet choose a structural remedy. E.ON urges the Commission to look at the full depth and breadth of its existing powers to monitor and fully redress any abuses in the allocation of transmission services before considering structural unbundling. Similarly, TVA notes that the Commission already has the option to impose a structural remedy on a case-by-case basis.[102]

Commission Determination

122. The Commission will, as proposed in the NOPR, continue to require functional—rather than corporate or structural—unbundling. As explained in the NOPR, for public utilities that keep transmission and generation assets in the same corporate entity, the Commission has strict Standards of Conduct that require the separation of the utilities' transmission system operations and wholesale marketing functions.[103] These rules 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.

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 (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

[101] *E.g.*, Santee Cooper, LPPC, TVA, Tacoma, Southern, MISO Transmission Owners, and E.ON.

[102] Some commenters argue that adoption of the ''open dispatch'' proposals raised by commenters such as Chandley-Hogan and PJM would constitute a departure from functional unbundling. We discuss the ''open dispatch'' and similar proposals in section V.C below.

[103] The rules were first established in Order No. 889. *See* Order No. 889 at 31,595. The Standards of Conduct rules were later replaced by a broader set of rules adopted in Order No. 2004, which were subsequently vacated in part by the United States Court of Appeals pending remand proceedings before the Commission. *See Standards of Conduct for Transmission Providers*, Order No. 2004, 68 FR 69134 (Dec. 11, 2003), FERC Stats. & Regs. ¶ 31,155 (2003), *order on reh'g*, Order No. 2004–A, 69 FR 23562 (Apr. 29, 2004), FERC Stats. & Regs. ¶ 31,161 (2004), order on *reh'g*, Order No. 2004–B, 69 FR 48371 (Aug. 10, 2004), FERC Stats. & Regs. ¶ 31,166 (2004), *order on reh'g*, 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).

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 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 to contain the revised provisions adopted in the Final Rule, rather than the transmission provider's entire *pro forma* OATT.[106] After the submission of their

[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.

[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.

[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

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 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, 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 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-

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.

[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.

[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 Web site at the following location *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp*.

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**.

2. ISO and RTO Public Utility Transmission Providers and Transmission Owner Members of ISOs and RTOs

143. With respect to an ISO or RTO public utility transmission provider, the Commission recognized in the NOPR that such an entity may already have tariff terms and conditions that are superior to the *pro forma* OATT. The Commission also noted that the purpose of this rulemaking is not to redesign approved, fully-functioning RTO or ISO markets. Thus, the Commission proposed to require ISO and RTO transmission providers to submit FPA section 206 compliance filings, within 90 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 or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions to the *pro forma* OATT. The Commission also proposed to allow ISO and RTO transmission providers, after making their FPA section 206 compliance filings, to submit filings under FPA section 205 proposing rates for the services provided for in their tariffs, as well as non-rate terms and conditions that differ from their existing tariffs and those set forth in the Final Rule if those provisions are consistent with or superior to the *pro forma* OATT. The Commission did not address the specific obligations of transmission owning members of ISOs and RTOs.

Comments

144. Several commenters support applying the revised *pro forma* OATT to ISOs and RTOs and requiring ISOs and RTOs to justify any variations therefrom. MidAmerican argues that universal application of the revised *pro forma* OATT is important because not every ISO or RTO transmission provider has existing tariff terms and conditions that are consistent with or superior to the OATT. Old Dominion also supports the Commission's compliance proposals for ISOs and RTOs. NRECA similarly states that RTOs, ISOs and ITCs should not be automatically exempt from any aspect of the rules governing open access transmission service, including the planning requirements. APPA asserts that in their filings, RTOs should be required to show how their transmission service packages, including features such as long term transmission rights, ancillary services, and treatment of losses, are consistent with or superior to the newly revised *pro forma* OATT. Moreover, APPA argues, the Commission should not allow RTOs to use their avowed independence as a justification for transmission services that in fact do not meet the consistent with or superior to standard.[109]

145. On the other hand, numerous commenters argue that the proposed compliance process is burdensome and could require ISOs and RTOs to have to relitigate already-approved OATT provisions. The ISOs and RTOs generally argue that, given the nature of the services they offer, many of the proposed revisions do not apply to their OATTs. Many commenters urge the Commission to adopt a more limited compliance filing process. Some commenters, for example, argue that the Commission should only require ISOs and RTOs to submit compliance filings that are limited to the specific *pro forma* tariff revisions set forth in the Final Rule. Duke argues that ISOs and RTOs should only be required to make a single filing that revises their OATTs in a manner that takes into account the nature of the OATT service provided by that ISO or RTO and whether a reform adopted in the Final Rule is relevant to the ISO's or RTO's OATT. EEI urges the Commission to require ISOs and RTOs to adopt only those OATT reforms that are necessary to improve the quality of transmission service that is provided by an ISO or RTO. EEI adds that those who protest an ISO's or RTO's assertion that an existing provision is consistent with or superior to the revised *pro forma* OATT should have the burden to demonstrate otherwise. The ISOs and RTOs similarly argue that, absent a specific demonstration that an ISO's or RTO's OATT provisions are unjust and unreasonable, the compliance filing requirements should not apply to ISOs and RTOs.

146. EEI urges the Commission to clarify that the 90-day filing should include the following materials: Revisions of tariff provisions that conform to the revisions in the *pro forma* OATT that are appropriate, given the ISO or RTO's market structure; statements supporting the provisions of the tariff that the ISO or RTO believes are consistent with or superior to the revised *pro forma* OATT; and justifications that support excluding revisions of the provisions that the ISO or RTO believes are not consistent with or superior to the revised *pro forma* OATT. EEI also interprets the NOPR proposal to mean that an ISO or RTO immediately may make a separate filing proposing further modifications, including revisions to the newly-effective provisions of the *pro forma* OATT, that are consistent with or superior to the just-filed modifications.

147. SPP urges the Commission to affirm that ISOs and RTOs will not be required to rejustify their previously-approved non-*pro forma* tariff provisions, but rather only the new or revised tariff provisions expressly prescribed in the Final Rule. In its reply comments, SPP notes that the terms and conditions of its OATT are interrelated and work together to achieve a system of administration that fosters open and transparent transmission service and function as an integrated whole. Therefore, SPP asserts, the modification of one provision of its OATT will impact several other provisions and the process of rejustifying one aspect of the tariff likewise will implicate other terms and conditions.

148. Indianapolis Power argues that tariff changes resulting from this rulemaking should be included only with the support of the ISO and RTO members who bear the costs and are in the best position to judge the benefits.

149. On reply, ISO/RTO Council generally argues that there is no factual or legal support for the ISO/RTO compliance procedures advocated by commenters such as APPA. ISO/RTO Council states that the OATTs of ISOs and RTOs were developed through extensive stakeholder procedures and subject to the Commission's filing, notice, comment, and approval processes under FPA section 205. ISO/RTO Council asserts that to adopt the post-hoc, open-ended review advocated by these parties would give disgruntled participants a ''second bite'' at legally effective OATT terms and would undermine the very stakeholder and regulatory processes by which ISOs and RTOs were established. MISO in particular argues that APPA's proposal ignores that ISO and RTO tariffs have already been determined to be just and reasonable and consistent with or superior to the Order No. 888 *pro forma* OATT, is profoundly inconsistent with the Commission's policy of encouraging RTOs as an option to ensure non-discriminatory open access transmission service, and is impracticable unless the intent is to grind RTO markets to a halt. MISO states that each RTO tariff has

[109] *See also* CMUA Reply.

dozens, or perhaps hundreds, of Commission-approved deviations and, in its view, reopening these issues would not be in the public interest and would consume enormous resources of both the RTOs and the Commission.

150. Southern, in its reply comments, argues that ISOs and RTOs are essentially requesting to be exempted from the requirements of this proceeding. Southern states that all transmission service revisions/reforms adopted in this proceeding should apply uniformly to all transmission providers, including ISOs and RTOs. Southern contends that ISOs and RTOs are increasingly subject to complaints alleging discriminatory treatment and asserts that the highly partisan attacks made by several RTOs against vertically-integrated utilities further calls into question whether ISOs and RTOs are not susceptible to taking discriminatory actions. In addition, Southern argues, such exemptions would likely result in seams issues.

151. Some commenters state that the Commission should identify the specific reforms it will apply to RTOs and ISOs and provide more general guidance as to how it intends to apply the consistent with or superior to standard to ISO/RTO tariff provisions. National Grid asserts that the Commission properly identified these provisions in the NOPR when the Commission concluded that there may be elements of the proposed reforms that are superior to what currently exist in some RTOs or ISOs, *e.g.*, transparency, data exchange, or planning. MISO/PJM States identify six areas as potentially applicable to RTOs: Hourly firm transmission service; obligation to expand capacity; joint ownership; reservation priority; ancillary services; and *pro forma* OATT definitions. MISO/PJM States also identify eleven areas as not applicable to RTOs: Undue discrimination generally; transmission pricing; remedies, penalties and enforcement; changes in receipt and delivery points (redirects); rollover rights; rules, standards and practices governing the provision of transmission service; joint transmission planning; tariff compliance review; hoarding of transmission capacity; curtailments; and ancillary services. APPA, in its reply comments, opposes granting a blanket exemption for ISOs and RTOs from any portion of the compliance filing requirement.

152. CAISO urges the Commission to clarify how it should provide for changes in the Final Rule to transmission services that it does not provide or which are clearly incompatible with the transmission service model it employs. In their reply comments, CMUA and APPA oppose this request for clarification. CMUA argues that CAISO's failure to provide any long-term transmission service renders its transmission service markedly inferior to the firm transmission service under the *pro forma* OATT. CMUA maintains that, instead of affirmatively embracing its obligation to show that its transmission service offering, once supplemented with long-term transmission rights that fully comply with all seven guidelines set out in Order No. 681, will meet the ''consistent with or superior to'' standard of Order No. 888, CAISO instead asks to be exempted from any such requirement.

153. Xcel and Indicated New York Transmission Owners assert that the Commission should allow regional variations to the extent that ISOs/RTOs can demonstrate that their OATT provisions meet the objectives of the Final Rule. Xcel argues that the consistent with or superior to standard may be too narrow because some changes to the OATT made by ISOs/RTOs are not as much ''superior'' or ''consistent with,'' as they are simply necessary because the tariff is regional. Indicated New York Transmission Owners argue that the Commission should not impose a consistent with or superior to standard generally reserved for transmission providers that are not members of an ISO/RTO. Indicated New York Transmission Owners assert that, to the extent that certain improvements could or should be made to the ISO/RTO OATTs, the Final Rule should permit the necessary flexibility for each ISO/RTO to propose and adopt such changes through their stakeholder governance processes, in order to address the unique market features and circumstances of each region.

154. PJM urges the Commission to include an ''independent entity variation'' standard similar to that used in Order No. 2003, which permitted an RTO to adopt interconnection procedures that are responsive to specific regional needs. NRECA responds that the Commission should not entertain PJM's request. While PJM's requested standard may have made sense in the context of generator interconnections, NRECA contends that it is inapposite to reform of the OATT. NRECA states that ISOs and RTOs should not be allowed to keep on file tariff provisions that possess the potential to allow for undue discrimination, even if the entity publishing the tariff is ostensibly independent of market participants and even if the proposed reforms do not directly improve the ''quality of'' transmission service, since the purpose of this rulemaking is to prevent undue discrimination in the provision of transmission service.

155. To whatever extent the Commission elects to exempt RTOs and ISOs from certain aspects of the *pro forma* OATT, E.ON asserts that the same consideration should be given to utilities that have entered into arrangements with alternative, Commission-approved, independent transmission organizations. In their reply comments, TDU Systems oppose this proposal arguing that these alternative constructs may not meet the independence criteria of Order Nos. 888 and 2000.

156. Several commenters urge the Commission to extend the proposed 90-day deadline for ISOs and RTOs to submit their compliance filings. EEI recommends that the Commission clarify that it will grant an extension of time if the stakeholder process prevents an ISO or RTO from obtaining stakeholder approval of tariff changes within the 90-day deadline. SPP requests a minimum of 120 days for compliance. National Grid and MISO (in its reply comments) propose 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.

Commission Determination

157. The Commission adopts the compliance procedures proposed in the NOPR, with certain revisions and clarifications. We will require ISO and RTO transmission providers to submit FPA section 206 compliance filings, within 210 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 or that demonstrate that their existing tariff provisions are consistent with or superior to the revised provisions of the *pro forma* OATT. As with non-ISO/RTO transmission providers, however, we will not require ISO and RTO transmission providers to ''rejustify'' existing provisions in their OATTs that are not affected in a substantive manner by the revisions to the *pro forma* OATT in the Final Rule. As we explained above, we find that such a process is unnecessary, given that we have already found these provisions to be consistent with or superior to the Order No. 888 *pro forma* OATT and these provisions are not substantively affected by the reforms we adopt today.

158. We also recognize, as we did in the NOPR, that some of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission

providers as they are to non-independent transmission providers. For example, many ISOs and RTOs use bid-based locational markets and financial rights to address transmission congestion, rather than the first-come, first-served physical rights model set forth in the *pro forma* OATT. As we indicated in the NOPR, nothing in this rulemaking is intended to upset the market designs used by existing ISOs and RTOs. We also recognize that ISOs and RTOs may well have adopted practices that are already consistent with or superior to the reforms adopted here. For example, ISOs and RTOs tend to have transmission planning processes that are significantly more open and transparent than the processes used by non-independent transmission providers. We encourage ISOs and RTOs to meet with their stakeholders to discuss whether any improvements are necessary to comply with the Final Rule.

159. We reject Indianapolis Power's proposal to require tariff changes resulting from this rulemaking only with the support of the ISO and RTO members who may bear the costs associated with the revision. Indianapolis Power effectively asks that we allow ISO and RTO members to veto our decisions here, which is contrary to our duty to prevent undue discrimination in the provision of transmission service.

160. Regarding CAISO's request for clarification of how it should address changes in the Final Rule to transmission services that it does not provide or which are incompatible with its service model, we reiterate that CAISO—like any other ISO or RTO—has the opportunity to demonstrate that a variation from the tariff revisions adopted in the Final Rule satisfies the consistent with or superior to standard. We do not believe that the adoption of an ''independent entity variation,'' proposed by PJM, or a regional variation standard, proposed by Xcel and Indicated New York Transmission Owners, would be appropriate. Again, the Commission finds that the reforms adopted in this Final Rule are necessary to prevent undue discrimination in the provision of transmission service and any transmission provider, including an ISO or RTO, must demonstrate that variations 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 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]

164. In EPAct 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]

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

[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 Web site 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.

[112] *See* Order No. 888–A at 30,285–86.

[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 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.

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 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.

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.

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 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 wesTTrans (an OASIS site serving the Western Interconnection) thus making it available to third parties, and that its members outside the CAISO also pay a

[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.

[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.

[118] *E.g.,* Calpine, MidAmerican, and Xcel.

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 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 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

[119] *See also* APPA Reply.

[120] *See also* CMUA Reply and Santa Clara Reply.

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

[122] *Citing* Order No. 888–A at 30,287.

Department of the Treasury adopted final regulations that in effect provide that providing open access transmission does not constitute private use.[123] Therefore, EEI 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.

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 Web site 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 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 Web site, the Commission's Web site, or in some instances a regional entity's Web site (such as the wesTTrans 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 Web site. 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 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

[123] Treas. Reg. § 1.141–7(g).

[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.

[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 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.

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 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.

194. In the NOPR, the Commission proposed to address this potential for undue discrimination by requiring industry-wide consistency and transparency of all components of the ATC calculation methodology and certain definitions, data, and modeling assumptions. The Commission proposed to provide guidance regarding aspects of ATC calculations that should be more consistent and proposed to direct public utilities, working through NERC[133] and NAESB, to revise reliability standards and business practices that are relevant to ATC calculations. The Commission also proposed to require increased detail in Attachment C of each transmission provider's OATT and proposed amending the OASIS regulations to require increased transparency. Although commenters challenged aspects of this proposed remedy, no commenters challenged the underlying finding that ATC reform is necessary to remedy undue discrimination in the provision of transmission service.

195. The Commission also indicated that the lack of consistent, industry-wide ATC calculation standards poses a threat to the reliable operation of the bulk-power system, particularly because a transmission provider may not know of its neighbors' system conditions affecting its own ATC values. As a result of this reliability impact, the Commission observed that the proposed ATC reforms are also supported by FPA section 215(d)(5), through which the Commission has the authority to direct the ERO to submit a reliability standard that the Commission considers appropriate to implement FPA section 215.

196. In light of these concerns, we direct public utilities, working through NERC reliability standards and NAESB business practices development processes, to produce workable solutions to complex and contentious issues surrounding improving the consistency and transparency of ATC calculations. We are directing our guidance to public utilities and require that they implement our direction by working with NERC to develop reliability standards that accomplish the ATC reforms required in this rulemaking. We will coordinate our directives here with the ATC-related reliability standards that are pending in Docket No. RM06–16–000.[134] The specifics of our findings with respect to ATC reform are discussed below.

1. Consistency

197. In order to address the potential for remaining undue discrimination in the determination of ATC, the Commission proposed to require industry-wide consistency of certain definitions, data, and modeling assumptions of the ATC calculation.

a. Necessary Degree of Consistency

NOPR Proposal

198. In the NOPR, the Commission recognized that transmission providers use several basic types of ATC calculation methodologies (with various permutations), and did not propose to require a single ATC calculation methodology to be applied by all transmission providers. However, the Commission proposed to achieve greater consistency in ATC calculations by directing the development of consistent definitions of the ATC components,[135] as well as consistent data inputs, modeling assumptions, and data

[131] *See* Order No. 888–A at 30,289.

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

[133] All references to NERC in the context of developing reliability standards are to NERC as the Electric Reliability Organization (ERO).

[134] We note that many of the ATC-related reliability standards filed in Docket No. RM06–16–000 were not addressed by the NOPR in that proceeding, pending the submittal of additional information. *See Mandatory Reliability Standards for the Bulk-Power System*, 71 FR 64770 (Nov. 3, 2006), FERC Stats. & Regs. ¶ 32,608 at Appendix A (2006) (Reliability Standards NOPR).

[135] The ATC components are total transfer capability (TTC), existing transmission commitments (ETC), capacity benefit margin (CBM), and transmission reserve margin (TRM).

exchange and coordination protocols. The Commission also required each transmission provider using an Available Flowgate Capacity (AFC) methodology to explain its definition of AFC, its calculation methodology and assumptions, and its process for converting AFC into ATC.

Comments

199. While the majority of commenters [136] support the NOPR's proposal to increase consistency in the calculation of ATC, several caution the Commission to allow flexibility [137] in order to capture differences in system operations,[138] usage, market operations,[139] and topology. Many assert that industry-wide standardization of the ATC calculation might not be possible and suggest that the Commission consider interconnection-wide,[140] regional,[141] or even sub-regional standardization. NARUC urges the Commission to facilitate State commission participation in efforts to reform ATC methodologies and calculations on a regional or sub-regional basis. Conversely, several commenters suggest that, if the Commission considers allowing use of different ATC calculations, it must impose a heavy burden on any entity seeking to justify a departure from the interconnection-wide or regional ATC standard.[142]

200. Constellation proposes that the Final Rule establish a rebuttable presumption that the basic ATC calculation formula [143] set forth in NERC's current ATC definition be identical within a region and that each element of the calculation have the same meaning for all transmission providers. Williams requests on reply that the Commission establish an industry-wide standard for the calculation of ATC and emphasizes that a consistent and transparent approach to evaluating ATC and ATC/AFC modeling assumptions is a prerequisite to the elimination of the broad discretion afforded transmission providers and, with it, the subtle discrimination practiced against customers.

201. Southern suggests that the basic ATC calculation should be defined for both firm and non-firm ATC calculations and also proposes that the following basic formulas be used: ATC (firm) = TTC − Firm Commitments or ETC − TRM − CBM; and ATC (non-firm) = TTC − Firm and Nonfirm Commitments + Postbacks of Redirected and Unscheduled Service − TRM − CBM. In addition, TDU Systems requests that the Commission require standardization of methods for calculating AFC and require NERC to create a formal definition of AFC.

202. PNM–TNMP and Bonneville express concerns with imposing an industry-wide standardized ATC methodology, arguing that there are too many variables in the way systems are operated. In its reply comments, PNM–TNMP adds that NERC's ATC calculation method should take into consideration the need for regional variation, and focus on consistency in definitions and data inputs. WestConnect participants caution that the replacement of the contract path ATC approach used in the Western Electricity Coordinating Council (WECC) with a flowgate methodology could seriously disrupt transmission service in the Western Interconnection.

203. PGP states that, although regional and sub-regional consistency is a good idea, there is no need for the Commission to require ''consistent'' ATC methodologies; rather, the emphasis should be on transparency of the methodologies, inputs, calculations and outputs. Other commenters agree that the Commission should not require overall standardization of ATC calculations, but instead permit regional differences with respect to certain aspects of the calculation of ATC.[144] EEI argues that standardization of ATC methodologies would require transmission systems to adopt a ''lowest common denominator'' standard in order to ensure that system reliability is not compromised, which would result in a reduction in ATC. EEI suggests that the Commission should direct NERC to develop ATC calculation standards that incorporate regional variations in order to maximize confidence in standards and system use, and maintain reliability. In its reply comments, Exelon disagrees with EEI and states that there are no regional differences within the individual interconnections that would justify differences in the application of ATC calculations.

204. Exelon states that ATC definitions must be consistent so that the various ATC components such as TRM have the identical meaning for all industry participants. In addition, Exelon argues that each ATC component (ETC, TRM, and CBM) must be used in the same manner for all purposes (*e.g.*, granting transmission service to third parties or for the transmission provider's own network load).

205. At the October 12 Technical Conference, NERC recognized that the goal of achieving consistency may not mean that a single ATC methodology is required.[145] NERC explained that consistency can be achieved with a limited number of methodologies if the requirements of those methodologies are properly coordinated and communicated. NERC stated that the Standard Drafting Team modifying the modeling, data, and analysis (MOD) standards[146] relevant to ATC is developing a standard applicable to three ATC calculation methodologies: the rated system path methodology (contract path), the network response methodology (network ATC), and the network response flowgate methodology (network AFC). NERC and the other panelists agreed that the two network methodologies are very similar in technique. NERC argued that the ultimate goal of ATC-related reforms should be to standardize definitions. The entire panel agreed that definitions must be consistent and a panelist representing Constellation asserted that broad differences in the core definitions of the ATC calculation are neither rational nor explainable.[147]

206. New Mexico Attorney General recommends that the Commission allow a utility to waive the requirement to make certain elements of ATC more consistent if the utility can show that it is making adequate progress towards developing consistent and transparent ATC calculations at the sub-regional level.

Commission Determination

207. The Commission adopts the NOPR proposal to require industry-wide

[136] E.g., Alcoa, Alliance, Ameren, Arkansas Commission, Arkansas Municipal, AWEA, Duke, E.ON, EEI, ELCON, EPSA, Exelon, LDWP, MidAmerican, NRECA, NPPD, NERC, Occidental, Powerex, PJM, PPL, Progress Energy, Project for Sustainable FERC Energy Policy, Santee Cooper, Southern, Suez Energy NA, SPP, TAPS, TVA, TDU Systems, TranServ, Tacoma, TANC, WECC, WestConnect, and Xcel.

[137] *E.g.* Allegheny, Entergy, Indianapolis Power, North Carolina Agencies, and NARUC.

[138] *E.g.* Bonneville, Northwest IOUs, and NorthWestern.

[139] *E.g.* CAISO.

[140] *E.g.* Ameren and Tacoma.

[141] *E.g.* APPA, Barrick Reply, Duke, EEI, Imperial, International Transmission, LDWP, NARUC, Nevada Companies, New York Commission, NRECA, MidAmerican, Occidental Reply, Pinnacle, PNM-TNMP, Public Power Council, CREPC, Salt River, Seattle, South Carolina E&G Reply, SPP Reply, Utah Municipals, and WPS Companies Reply.

[142] *E.g.* TDU Systems and East Texas Cooperatives Reply.

[143] *E.g.*, ATC = TTC − (ETC + CBM + TRM).

[144] *E.g.*, EEI Reply, NARUC Reply, and Powerex Reply.

[145] Transcript of October 12 Technical Conference at 125–150.

[146] MOD standards refers to Modeling, Data, and Analysis Reliability Standards.

[147] Transcript of October 12 Technical Conference at 149–160.

consistency of all ATC components and certain definitions, data, and modeling assumptions. The Commission also will require each transmission provider to include in Attachment C to its OATT detailed descriptions for calculating both firm and non-firm ATC, consistent with the requirements of this Final Rule. The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (*i.e.*, TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results. The Commission finds that these reforms will facilitate development of a more coherent and uniform determination of ATC.

208. We reject requests to establish a single methodology for calculating ATC, however, for several reasons. It is not our intent to require transmission providers to incur the expense of developing and adopting a new one-size-fits-all software package to calculate ATC. We also see little benefit in requiring a ''lowest common denominator'' ATC calculator. While a uniform methodology may result in all transmission providers calculating ATC in an identical manner, it would also likely lead to software implementation costs in excess of the resulting benefits. More importantly, we find that the potential for discrimination does not lie primarily in the choice of an ATC calculation methodology, but rather in the consistent application of its components.

209. All ATC calculation methodologies derive ATC by modeling the system to establish TTC, expressed in terms of contract paths or flowgates, and reducing that figure by existing transmission commitments (*i.e.*, ETC), a margin that recognizes uncertainties with transfer capability (*i.e.*, TRM), and a margin that allows for meeting generation reliability criteria (*i.e.*, CBM). These calculation methodologies are developed based on physical characteristics of the transmission provider's transmission system, historical modeling practices, and processes developed for collection of input data related to transmission provider's own system conditions as well as relevant data that model neighboring systems' conditions. We therefore find that it is not the methodologies for calculating ATC themselves that create the opportunity for undue discrimination. Instead, we find that the potential for undue discrimination stems from two main sources:

(1) Variability in the calculation of the components that are used to determine ATC and (2) the lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider.[148] The combination of a lack of consistency of the components of the ATC calculation coupled with the lack of transparency leaves customers and regulators unable to verify ATC calculations and may allow transmission providers to calculate ATC in different ways for different customers.

210. Accordingly, we conclude that industry-wide consistency of all ATC components (TTC, ETC, CBM, and TRM) and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC will reduce the opportunities for the exercise of discretion that may lead to undue discrimination against unaffiliated transmission customers. The Commission understands that NERC currently is developing standards for three ATC calculation methodologies (contract or rating path ATC, network ATC, and network AFC).[149] If all of the ATC components and certain data inputs and assumptions are consistent, the three ATC calculation methodologies being finalized by NERC through the reliability standards development process will produce predictable and sufficiently accurate, consistent, equivalent, and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology. The Commission instead concludes that use of the ATC calculation methodologies included in reliability standards currently being developed by NERC is acceptable.

211. As TDU Systems note, there is neither a definition of AFC in NERC's Glossary nor an existing reliability standard that discusses the AFC method. In order to achieve consistency in each component of the ATC calculation (discussed below), we direct public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Transmission providers using an AFC methodology must therefore convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to have consistent posting of the ATC, TTC, CBM, and TRM values on OASIS, we direct public utilities, working through NERC, to develop in the MOD–001 standard a rule to convert AFC into ATC values to be used by transmission providers that currently use the flowgate methodology.

212. The Commission also believes that further clarification is necessary regarding the calculation algorithms for firm and non-firm ATC.[150] Currently, NERC has no standards for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service and that greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) For firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the

[148] For example, utilities A and B would agree that ATC is derived by reducing TTC by the sum of ETC, CBM and TRM, but utility A may define ETC to include set-asides for contingencies while utility B may not.

[149] *See Transcript of October 12, 2006 Technical conference at 125.* Thee three methodologies are different computational processes to determine a transmission system's ATC. The first, contract path, examines TTC for every A-to-B path on the system in concert with all others, reduces ATC by path for ETC, TRM, and CBM, as appropriate, and produces ATC for each path. The second method, net work ATC, uses a simulator to look not at each path, but each transmission element (line, substation, *etc.*,), and rule first contingency simulations to establish ATC on a network basis. The third method, network AFC, uses a simulator to examine critical flowgates over a wider area, then requires a second step to convert AFC values to particular path ATC values.

[150] The NERC ATC definition does not differentiate firm and non-firm ATC from a high level generic ATC definition: ''A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.'' *See* North American Electric Reliability Corporation, *Glossary of Terms Used in Reliability Standards* (February 7, 2006).

transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows. We understand that these principles are currently followed by most transmission providers and believe they should be clearly set forth in the ATC-related reliability standards. As described below, each transmission provider's Attachment C must include a detailed formula for both firm and non-firm ATC, consistent with the modified ATC-related reliability standards.

213. We deny New Mexico Attorney General's request to grant waiver of the ATC consistency requirements to utilities that can show that they are making adequate progress toward developing consistent and transparent ATC calculations at the sub-regional level. While we certainly encourage regional consistency with respect to the ATC calculation methodology, we are not requiring consistency; therefore a waiver is not necessary. As discussed in more detail below, any request for waiver from these ATC calculation requirements must take place through the NERC reliability standards development process as a request for a regional difference, since the ATC requirements will be determined through the NERC reliability standards.

b. Process To Achieve Consistency

NOPR Proposal

214. In the NOPR, the Commission expressed confidence that the existing NERC and NAESB processes were well-suited to achieving greater consistency in ATC calculations. The Commission therefore proposed to require public utilities, working through NERC and NAESB, to revise the reliability standards and business practices relating to ATC, consistent with the guidance provided in the Final Rule, within 180 days after the publication of the Final Rule in the **Federal Register**.

Comments

215. Many commenters support the Commission's proposal directing NERC and NAESB to develop reliability standards and business practices addressing ATC.[151] In addition, several commenters urge the Commission to be more precise in differentiating between policy and business standards, and urge the Commission to provide more guidance to NERC and/or NAESB.[152] NRECA suggests that the Commission require NERC and NAESB to file the results of their processes with the Commission, give all interested parties an opportunity to comment on the proposals, and exercise its independent authority to review, and if necessary, remand the issues or proposals back to NERC and NAESB.

216. Occidental states on reply that it does not oppose NERC having a role in developing the basic requirements and standards for ATC. However, Occidental also urges the Commission to adopt a process similar to that employed in developing the Standards for Business Practices and Communication Protocols for Public Utilities, which were incorporated by reference into the *pro forma* OATT.[153] There, the Commission allowed NAESB's Wholesale Electric Quadrant to develop, with widespread industry input, business practice standards that the Commission then reviewed, adopted and required public utilities to include in their OATTs by reference.[154] Occidental claims that this process would ensure industry input in the development of the methodology for ATC calculations, as well as Commission review and approval of the methodology.

217. Several commenters raise concerns that six months may not be sufficient time to develop ATC-related reliability standards and business practices.[155] Exelon, MidAmerican and NARUC propose that the Commission grant NERC one year from the date of the Final Rule to develop the necessary reliability standards. NARUC agrees with one year, but requests flexibility to assure that the NERC and NAESB processes can be adequately completed. NERC also states that it expects the standards development process, already underway, to be finalized with standards submitted to the Commission prior to the summer of 2007. LPPC recommends that, within six months of the issuance of the Final Rule, NERC be required to submit a progress report addressing the status and a work plan for conclusion within the ensuing six months. NRECA proposes that the Commission closely monitor the NERC and NAESB process. Some commenters strongly oppose a flexible deadline, and urge the Commission to establish a firm deadline that must be met.[156]

218. At the October 12 Technical Conference, NERC informed participants that a great deal of progress has been made since the proposed standards developed by the NERC Standard Committee in February 2006 were generated to address the recommendations made by the Long-Term AFC/ATC Task Force.[157] However, NERC indicates that a significant amount of work remains before the standard revisions are considered complete. Since NERC would like to finalize its revised standards for submittal to the Commission for the summer of 2007, NERC has established an aggressive schedule of meetings for drafting which will be coordinated with NAESB.

219. PJM outlines several guidelines it suggests the Commission should give to NERC and NAESB regarding the standards development process and recommends that Commission staff participate in the standards development process. Williams and EPSA likewise request that the Commission provide clear guidance to NAESB to assure efficiency and timeliness of the process.

220. Some commenters prefer engagement of a fully independent organization to develop standards and practices related to ATC.[158] EPSA strongly urges the Commission to require all transmission providers outside of RTO areas to contract with an independent entity to develop and/or monitor ATC calculations. Although TDU Systems agree with EPSA that vertically-integrated transmission providers that are not subject to the independent oversight of an ISO/RTO retain inherent incentives to discriminate against competitors, they contend that the benefit of independent oversight of ATC calculations must be weighed against the cost of that oversight. Alcoa suggests engaging the Institute of Electrical and Electronics Engineers (IEEE) instead of the Commission's proposal to use NERC and NAESB. APPA opposes that position. New York Commission proposes that regional reliability organizations, rather than NERC, complete this task and that the ATC calculators be closely coordinated by

[151] *E.g.*, Allegheny, APPA, Arkansas Commission, Bonneville, CAISO, Constellation, E.ON, EEI, ELCON, Entergy, Exelon, FirstEnergy, LPPC, MidAmerican, New York Commission, NERC, Northeast Utilities, Project for Sustainable FERC Energy Policy, PNM–TNMP, Santa Clara, Southern, Tacoma, TransServ, and Utah Municipals.

[152] *E.g.*, EPSA and Williams.

[153] *Citing Standards for Business Practices and Communication Protocols for Pub. Utils.*, Order No. 676, 71 FR 26199 (May 4, 2006), FERC Stats. & Regs. ¶ 31,216 (2006), *order on reh'g*, Order No. 676–A, 116 FERC ¶ 61,255 (2006).

[154] *Citing id.* at P 20.

[155] *E.g.*, Constellation, Duke, EEI, Exelon, LPPC, MidAmerican, NARUC, Northwest IOUs, Public Power Council, CREPC, Southern, TDU Systems, and WestConnect.

[156] *E.g.*, Utah Municipals and Entegra.

[157] *Citing* Long-Term AFC/ATC Task Force Final Report (Revised April 14, 2005), *available at http://www.nerc.com/~filez/ltatf.html.*

[158] *E.g.*, Alcoa, Fayetteville, and MISO.

ISOs and RTOs.[159] PJM contends on reply that New York Commission's proposal for coordination of ATC between ISOs and RTOs has been fulfilled at least between PJM and its neighbors, arguing that New York Commission's proposal is unnecessary and would add a layer of bureaucracy and cost. TAPS expresses concern with the Commission proposal to use NERC and encourages the Commission to be precise in its direction to NERC to accomplish the needed objective.

Commission Determination

221. The Commission directs public utilities, working through NERC and NAESB, to modify the ATC-related reliability standards and business practices in accordance with specific direction provided in this Final Rule. As we explain above, the development of a more coherent and uniform determination of ATC across a region will help limit the potential for undue discrimination in the calculation of ATC. The Commission concludes that the NERC reliability standards development process and the NAESB business practices development process are the appropriate forums for developing this consistency.

222. NERC has been certified as the ERO and, as such, has been found to have the ability to develop reliability standards through processes with reasonable notice and opportunity for public comment. NERC's processes are open and provide due process as well as a balance of interests, while assuring independence from users and owners and operators of the bulk-power system. Moreover, NAESB has a long history of developing standard business practices for the electric industry, on which the Commission has relied in various contexts. While other entities may bring certain benefits, commenters have not demonstrated the superiority of IEEE, a regional reliability organization, or a particular RTO over NERC and NAESB. Once components of ATC are made consistent and ATC calculation methodologies are made transparent, opportunities for discretion that may lead to undue discrimination in the calculation of ATC will be sufficiently eliminated to invalidate the need for the creation of independent entities to oversee that calculation. To the extent that, even following the adoption of these reforms, customers have complaints regarding the calculations performed by individual transmission owners, they can be addressed on a case-by-case basis.

223. With respect to a timeline for completion, the Commission concurs with NERC that a significant amount of work remains to be done on ATC-related reliability standards development. We also agree with the many commenters who state that the NOPR's proposed six-month timeline is too short for such a complex assignment. Although NERC projects that it may be able to complete the process by the summer of 2007 (which is approximately six months from the date of the Final Rule), we believe NERC should have additional flexibility with respect to its timeline. Accordingly, we direct public utilities, working through NERC, to modify the ATC-related reliability standards within 270 days after the publication of the Final Rule in the **Federal Register**. We also direct public utilities to work through NAESB to develop business practices that complement NERC's new reliability standards within 360 days after the publication of the Final Rule in the **Federal Register**. Finally, we direct NERC and NAESB to file, within 90 days of publication of the Final Rule in the **Federal Register**, a joint status report on standards and business practices development and a work plan for completion of this task within the timeframe established above.[160]

c. Applicability to ISOs, RTOs, and Non-Public Utility Transmission Providers

NOPR Proposal

224. The Commission did not specifically address the application of the ATC-related reforms proposed in the NOPR to ISOs and RTOs or non-public utility transmission providers.

Comments

225. ISOs and RTOs believe that the Commission should not require wholesale revisions of RTO and ISO tariffs, even on such issues as ATC standards.[161] They caution that many regional grid operators' tariffs contain nonconforming provisions that were the product of extensive debate, litigation and settlements. In addition, some commenters point out that concern about ATC calculations is a non-issue in many ISO/RTO regions because transmission services in those regions are not based on physical transmission reservations.[162]

226. MISO argues that AFC calculation methodologies should be established via the RTO stakeholder process, not NERC. In its reply comments, Exelon expresses disagreement with MISO and states that there must be one standard for ATC calculations, not several methods based on the desires of different sets of stakeholders. Several commenters also believe that ISOs/RTOs should not be exempt from the requirements for consistent and transparent ATC calculations.[163]

227. EEI asks the Commission to require all municipal and other non-public utility transmission providers to adhere to any requirement for consistent and transparent ATC/AFC calculation. In its view, applying the ATC-related reforms to these nonjurisdictional entities would recognize the interconnected nature of the transmission grid. EEI argues that greater transparency and consistency in the provision of transmission service would be frustrated if all transmission providers do not have to comply. Other commenters reply that EEI's concerns are unfounded and describe an example in the WECC region, where the methodologies and practices regarding ATC calculations are developed by representatives from all affected transmission providers, utilities, and market participants, including nonjurisdictional entities.[164]

228. LPPC contends that the NERC reliability standards related to ATC calculation will already be applicable to both public and non-public utilities. LPPC argues that NERC standards, when final, will be filed with the Commission, become part of the ERO's mandatory reliability standards and will be fully applicable to otherwise nonjurisdictional entities. As a result, the ATC standards will be applicable to and enforceable upon all transmission owners, whether or not the transmission owner has an OATT.

Commission Determination

229. We discuss the applicability of the Final Rule to ISOs and RTOs in section IV.C.2 above. With respect to the application of the ATC requirements of this Final Rule to municipal and other non-public utility transmission providers, we likewise note that the applicability of the rule generally to such entities is addressed in section

[159] If ISOs and RTOs cannot perform the coordination function, New York Commission suggests the establishment of a Transmission Oversight Center to oversee the calculation of ATC within and between ISOs and RTOs.

[160] NAESB's work plan for developing business practices related to other reforms adopted in this Final Rule should be filed separately, as requested in Section IV.C.1.

[161] *E.g.*, PJM and MISO Transmission Owners, SPP Reply.

[162] *E.g.*, ISO/RTO Council, ISO New England, and Pennsylvania Commission.

[163] *E.g.*, NRECA and TDU Systems.

[164] *E.g.*, Lassen and Public Power Council.

IV.C.3. We note here, however, that such entities will be required to comply with reliability standards developed under FPA section 215. As LPPC acknowledges, once these reliability standards are approved they will become part of the ERO's mandatory reliability standards and, thus, will be applicable to and enforceable upon all transmission owners, whether or not the transmission owner has adopted the OATT.

d. Alternatives to ATC Consistency

Comments

230. Some commenters contend that the NOPR is focused too narrowly on simply improving the consistency and transparency of ATC determinations and suggest that a focus on balancing (or dispatch) services and how those are priced would allow the Commission to avoid the pitfalls inherent in the ATC approach.[165] In their view, such an approach would eliminate much of the difference between how third parties are treated in RTO versus non-RTO systems. Constellation encourages the Commission to consider requiring transmission providers to implement all-inclusive, security constrained economic dispatch processes. In reply comments, Chandley-Hogan argue that the Commission's ATC-related proposals in the NOPR confuse how transmission service is actually provided in most of the United States and, as a result, the Commission's analysis of perceived problems in the calculation of ATC is flawed, inconsistent with network realities and the laws of physics, and incompatible with reliable operations.

231. Contrary to the above claims, some commenters find that ATC provides a functionally useful measure of available capacity and has certain advantages over alternative models.[166] These commenters argue that the factual record does not support conclusions that bid-based, marginal cost dispatch by a third party is inherently more efficient or inherently more likely to remedy undue-discrimination than the OATT model, and cannot overcome the considerable real world obstacles to pure economic redispatch, including overlapping and dynamic constraints, and the physical realities in the Western Interconnection that often limit the pool of resources that can be redispatched to solve constraints. LPPC contends that the principal advantage of ATC is the certainty that it provides for available capacity, suggesting that the contract path paradigm facilitates long-term bilateral contracting.

Commission Determination

232. In this rulemaking, the Commission is requiring consistency in the determination of ATC with the purpose of improving a customer's ability to receive transmission service on a non-discriminatory basis. These reforms are fully consistent with operational reality, and we decline to mandate the security constrained economic dispatch alternative proposed by Chandley-Hogan. Chandley-Hogan argue that it would be unduly discriminatory to exclude third-party generators from an efficient dispatch to serve native load and therefore a centralized, bid-based market is required. We agree that a centralized bid-based market can benefit customers and, over a large region, can manage congestion efficiently. We do not believe, however, that mandating that result—essentially requiring that Day 2 RTOs be adopted in every region of the country—is necessary to remedy undue discrimination in the provision of transmission service. The concern raised by Chandley-Hogan is not related solely to the nondiscriminatory use of the transmission system. It also implicates the purchase decisions of transmission providers on behalf of their native load customers. These decisions are regulated primarily by the states and we decline to take generic action in this rulemaking to reform the processes by which those purchases are made.

e. ATC Components

233. The next several sections address components of ATC that must be made consistent to remove the potential for undue discrimination, namely TTC/TFC, ETC, CBM, and TRM.

(1) Total Transfer Capability (TTC)/Total Flowgate Capability (TFC)

NOPR Proposal

234. The Commission proposed to direct public utilities, working through NERC, to develop consistent practices for calculating total transfer/flowgate capability (TTC/TFC). Although the NERC reliability regions have historically calculated transfer capability using different approaches, the Commission expressed its view that guidelines for a common approach to calculating transfer capability are achievable. The Commission also stated that the criteria used for identifying flowgates and determining TFC could be more consistent.

Comments

235. Entergy supports the development of consistent practices for determining transfer capability while maintaining flexibility to recognize regional and system-specific differences. APPA agrees that the calculation of TTC/TFC is, for the most part, a regional calculation. APPA states that the Western Interconnection and ERCOT use their own methods, which are generally applied system-wide. APPA believes that more standardization and coordination of TTC/TFC among transmission providers in the Eastern Interconnection, where two primary methods are used to calculate TTC or TFC, would be desirable because of reported loop-flow problems in the Eastern Interconnection.

236. In order to increase transfer capability from existing facilities, AWEA proposes that the Commission direct NERC, as part of developing consistent ATC standards, to investigate the impact of implementing dynamic line ratings in TTC/TFC calculations and propose protocols to effectuate such a program. In response to AWEA's proposal, commenters state that if the Commission decides to provide guidance to NERC with regard to dynamic line ratings, the Commission should encourage NERC to develop standards with regard to dynamic line ratings in the operating horizon, but not in the planning horizon.[167]

Commission Determination

237. The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to develop consistent practices for calculating TTC/TFC. We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the *pro forma* OATT and for transfer capability for native load and reliability assessment studies.

238. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected.[168] However, as already discussed above regarding ATC, the TTC requirements will be determined by the NERC reliability standards and any request for a regional difference from the reliability standards must take place through the NERC process.

[165] *E.g.,* Chandley-Hogan, EPSA, PJM, San Diego G&E, and Transparent Dispatch Advocates Reply.

[166] *E.g.,* APPA, CMUA, CPA, Duke, EEI, Entergy, LPPC, Public Power Council, Sacramento, and WestConnect Reply.

[167] *E.g.,* MAPP and MidAmerican.

[168] For example, WECC has a documented open process for establishing TTC for the Western Interconnection.

239. With respect to AWEA's proposal regarding implementing dynamic line ratings in TTC/TFC calculations, the Commission finds that this proposal is outside the scope of this rulemaking as it does not appear to relate to undue discrimination in transmission service and, in any event, would best be addressed in the first instance through the NERC reliability standards development process, addressing reliability standards that regulate facility ratings. If AWEA desires to pursue this proposal, it should propose an appropriate dynamic line rating standard within the ERO's reliability standards development process.

(2) Existing Transmission Commitments (ETC)

NOPR Proposal

240. In the NOPR, the Commission expressed its view that the lack of consistency in modeling of existing transmission commitments (ETC) resulted in excessive discretion in determining how much capacity a transmission provider sets aside for native load, including its network customers. The Commission therefore proposed the development of a consistent methodology for determining the capacity needed and set aside for native load usage. The Commission also proposed that accounting for transmission reservations in an ATC/AFC calculation be more consistent. The Commission further proposed that public utilities, working through NERC, establish and specifically identify the reservations to be used in determining ETC.

Comments

241. Entegra and PGP support increasing consistency in determining ETC. APPA agrees that it would be helpful to standardize the method of accounting for ETC on an interconnection-wide basis. APPA states, however, that flexibility might be required among the interconnections. TDU Systems requests that the Commission define with specificity the types of transmission service requests or scheduled transmission transactions that should be included in ETC and agrees with the Commission that inclusion of all requests for transmission service in ETC is likely to overstate usage of the system, thus understating ATC. It suggests that the Commission develop a bright line method for calculating ETC. NERC notes that its proposed reliability standards would define ETC and require appropriate documentation. NERC adds, however, that the components included in ETC appear to be candidates for business practices rather than reliability standards.

242. Williams proposes that ETC be the subject of an expanded definition and that native load growth projections be based on verifiable data provided by an independent source. It also states that transmission providers should be required to update ATC based on each confirmed transmission service reservation (point-to-point or network, firm or non-firm).

Commission Determination

243. To achieve greater consistency in ETC calculations and further reduce the potential for undue discrimination, the Commission adopts the NOPR proposal and directs public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that NERC will address ETC through the MOD–001 reliability standard rather than through a separate reliability standard.[169] By using MOD–001, the ETC calculation can be adjusted to be applicable to each of the three ATC methodologies under development by NERC.

244. In order to provide specific direction to public utilities and NERC, we determine that ETC should be defined to include committed uses of the transmission system, including (1) Native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations,[170] (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM.[171] In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.

245. We agree with TDU Systems that inclusion of all requests for transmission service in ETC would likely overstate usage of the system and understate ATC. We therefore find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at POR. This will prevent overly unrealistic utilization of transmission capacity associated with power output from a generator identified as a POR. We direct public utilities, working through NERC, to develop requirements in MOD–001 that lay out clear instructions on how these reservations should be accounted. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.

246. We agree with NERC that some elements of ETC are candidates for business practices rather than reliability standards. Accordingly, we direct public utilities, working through NAESB, to develop business practices necessary for full implementation of the developed MOD–001 reliability standard.

247. We decline to adopt Williams's proposal to require that native load growth be based on the verifiable data provided by an independent source. Through increased consistency and transparency of ATC determinations, including requirements for posting additional data, third parties will be able to verify the accuracy of ETC, helping to eliminate opportunities for undue discrimination.

(3) Capacity Benefit Margin (CBM)

NOPR Proposal

248. In the NOPR, the Commission proposed three options to address the CBM component of ATC: (1) Have NERC develop clear standards for how the CBM value should be determined, allocated across transmission paths, and used; (2) charge an entity for which transfer capability has been set aside to meet generation reliability criteria a separate rate for this service; or (3) eliminate CBM and require an entity reserving ATC to meet generation reserve (currently through CBM) to designate network resources on the other side of the interface and make an associated transmission service reservation.

Comments

249. Numerous commenters support the Commission's proposed option one, requiring NERC to develop clear standards for how the CBM value should be determined, allocated across

[169] The purpose of MOD–001 is to promote the consistent and uniform application of transfer capability calculations among the transmission system users.

[170] By ''appropriate,'' we mean that reservations accounted for under ETC depend on the firmness and duration of the reservation. The specific characteristics should be developed in the reliability standard.

[171] TRM also includes such things as loop flow and parallel path flow.

transmission paths, and used.[172] They believe that CBM ensures the ability to import needed power to support system conditions. TVA argues that option two would be costly and may cause some systems to forego CBM, thereby jeopardizing service to native load customers. PJM states that option two is irrelevant in PJM since PJM ''totals'' reservations and decides when CBM can be used. Supporters of option one criticize option three, elimination of CBM, as costly and a threat to transmission system reliability. Southern, Progress Energy, and PJM emphasize that, without CBM, the LSEs would need to increase their reserve margin by contracting for additional generation capacity, costing millions of dollars. In addition, Ameren and TVA believe that CBM elimination will increase the likelihood of widespread blackouts in emergency conditions.

250. At the October 12 Technical Conference, Exelon supported option two proposing a charge for CBM. Exelon contended that, in a rate-making context, there would be an increase in the divisor of the rate by the amount of CBM set-aside which would lower the point-to-point charge. Consequently, those not benefiting from the CBM set-aside effectively would be paying a lower charge.

251. Constellation and Morgan Stanley support the elimination of CBM and argue that CBM and TRM are often used interchangeably and result in duplicative transmission set-asides. They also argue that there is no compelling need for CBM in the current liquid market environment. In addition, Morgan Stanley states that LSEs affiliated with the transmission provider should not be allowed to use CBM for long-term planning purposes as an excuse to avoid undertaking needed resource additions or to conceal the true cost of their load serving functions. Furthermore, the Commission should not be distracted by assertions that such long-term arrangements are necessary for ''reliability,'' when in fact they are simply a way to protect the economic interests of a particular entity.

252. Duke replies that Constellation mistakenly believes that CBM is currently only available to a transmission provider's native load when, in fact, for those transmission providers that establish CBM, it should be established for the load of all LSEs in the control area. Duke contends that not all transmission providers set aside capacity through CBM for their native load; to the extent that a transmission provider does not set aside CBM, there should be no obligation to allow other LSEs to do so. Duke proposes that the Commission should continue to permit such flexibility.

253. NERC takes no position on CBM, expecting that the issue can be settled through the NERC and NAESB Procedure for Joint Standards Development and Coordination and through other open forums.

254. TAPS suggests that the Commission ensure that all LSEs have both access to CBM to meet their reserve-sharing needs and meaningful input into how much CBM is reserved. To do so, TAPS recommends the creation of a reserve-sharing group made up of the transmission provider and LSEs it serves. It argues that this would remove reservation decisions from the sole discretion of the vertically-integrated transmission provider and instead have them made by the transmission provider/LSE reserve-sharing group, subject to dispute resolution at the Commission. All LSEs would be invited to participate in the studies as well as review the results and assumptions. Moreover, once a regional planning process is established, as proposed in the NOPR, TAPS recommends that the regional planning group be required to approve the CBM reservation as well.

255. Williams suggests that a transmission provider must designate network resources and reserve firm transfer capability on both sides of the control area transmission interface in order to reserve CBM. Duke replies that, although some commenters prefer eliminating CBM and replacing it with additional designated network resources, CBM is the preferable option because it is less costly. Duke further argues that the choice is between setting aside both additional transmission and generation capacity to deal with emergencies (the additional designated network resource approach) versus setting aside only transmission (the CBM approach). Having to procure additional designated network resources to keep in reserve reduces one of the main benefits of interconnected operations. Duke argues that eliminating CBM would drive up costs for network customers, as they would have to procure additional generation and transmission resources. EEI adds that such a proposal may result in increased LSE reserve requirements, over-building of generation supply, and a reduction, rather than an increase, in ATC.

Commission Determination

256. The Commission concludes that it is appropriate to allow LSEs to retain the option of setting aside transfer capability in the form of CBM to maintain their generation reliability requirement. We agree with commenters that, without CBM, LSEs would have to increase their generation reserve margins by contracting for generation capacity, which may result in higher costs without additional reliability benefits. We require, however, the development of standards for how CBM is determined, allocated across transmission paths, and used in order to limit misuse of transfer capability set aside as CBM. Transmission providers also must reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service to ensure comparable treatment for point-to-point to customers.

257. The Commission therefore adopts a combination of the NOPR options one and two, and declines to adopt option three. First, we require public utilities, working through NERC and NAESB, to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. We understand that NERC has already begun the process of modifying several of the CBM-related reliability standards and that the drafting process is a joint project with NAESB. Second, we require transmission providers to reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service.

258. We note that there is broad concern that eliminating CBM (option three) would impose extraordinary costs for meeting generation reliability criteria, which then may lead utilities to reduce their generation reliability requirement to avoid the cost increase. We believe that the reforms reflected in combining options one and two are sufficient to remedy undue discrimination and that the adverse effects associated with option three are neither warranted nor required. We reject Morgan Stanley's call for CBM elimination on the grounds that CBM is acting as a disincentive to undertake needed generation resource additions. It would be inappropriate for the Commission to restrict the ability of an LSE to determine how best to meet its generation reliability criteria.

259. To ensure CBM is used for its intended purpose, CBM shall only be used to allow an LSE to meet its generation reliability criteria. Consistent with Duke's statement, we clarify that

[172] *E.g.,* Allegheny, Ameren, EEI, Duke, NRECA, TVA, APPA, Bonneville, EPSA, FirstEnergy, Indianapolis Power, MidAmerican, Pinnacle, PJM, PGP, PNM–TNMP, Public Power Council, Sacramento, Seattle, South Carolina E&G, TANC, TDU Systems, and Wisconsin Electric.

each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, State, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability (LOLP), the loss of largest units, *etc.*

260. We direct public utilities, working through NERC, to develop clear requirements for allocating CBM over transmission paths and flowgates. While we do not mandate a particular methodology for allocating CBM to paths and flowgates, one approach could be based on the location of the outside resources or spot market hubs that an LSE has historically relied on during emergencies resulting from an energy deficiency.

261. We concur with TAPS' proposal that all LSEs should have access to CBM and meaningful input into how much transfer capability is set aside as CBM. In the transparency section below, we provide detailed requirements regarding availability of documentation used to determine the amount of transfer capability to be set aside as CBM and the posting of CBM values and narratives. Access to this documentation will enable LSEs to validate how much transfer capability is set aside as CBM on each system and provide them with information to question whether the set-aside is consistent with the reliability standards and this Final Rule.

262. Concerning TAPS' proposal to remove the reservation decision from the sole discretion of transmission providers, we determine that LSEs should be permitted to call for use of CBM, if they do so pursuant to conditions established in the reliability standards development process. We direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM. In addition, we direct that transmission set aside as CBM shall be zero in non-firm ATC calculations. Finally, we order public utilities to work with NAESB to develop an OASIS mechanism that will allow for auditing of CBM usage.

263. We also require transmission providers to design their transmission charges to ensure that the class of customers not benefiting from the CBM set-aside, *i.e.*, point-to-point customers, do not pay a transmission charge that includes the cost of the CBM set-aside. To do this, transmission providers are required to submit redesigned transmission charges that reflect the CBM set-aside through a limited issue FPA section 205 rate filing as part of its initial ATC-related compliance filing. These filings, which may be submitted within 120 days after the publication of the Final Rule in the **Federal Register**, may be limited to the rate design change only, *i.e.*, they will not require the submission of cost of service data or a revision to the transmission provider's revenue requirement.

264. With respect to TAPS' proposal that all LSEs should be allowed to use CBM to meet their reserve-sharing needs, we believe that TRM is the appropriate category for that purpose, not CBM. We reject TAPS' proposal to use CBM for the LSE's reserve-sharing needs, but instead make TRM available for the incremental power flows resulting from reserve sharing, as explained next.

265. As we are rejecting option three, which would have required the reservation of transfer capability rather than using CBM, we also reject Williams' proposal to require the reservation of transfer capability on both sides of an interface for CBM.

(4) Transmission Reserve Margin (TRM)

NOPR Proposal

266. Finally, the Commission proposed the development of reliability standards MOD–008 and MOD–009 [173]that specify the uncertainties that TRM could be used to accommodate, which could include (1) Load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC reliability standards development process.

Comments

267. Most commenters agree that the existing definitions for TRM require clarification.[174] Commenters also agree that NERC should be required to develop clear standards for the determination of TRM, including specifying the criteria used in the determination of TRM.[175] PNM–TNMP supports the Commission's proposal, pointing out that the implementation of the current NERC standards definition for TRM and CBM could result in its double-counting, which must be eliminated. APPA members in the Western Interconnection suggest that regional variations be permitted. They also note that the modeling methods used by WECC and its sub-regions may differ from those used in the Eastern Interconnection. For example, they contend that uncertainties associated with transmission maintenance schedules that are driven by hydro-production curves will seasonally affect TRM set-asides on certain transfer paths. PJM believes that the TRM methodology should be consistent at the regional reliability organization level. PJM also contends that TRM should be coordinated, exchanged and respected on external flowgates and that the concept of a maximum TRM, by percentage, should be adopted in the NERC standards.

268. Consistent with its position on CBM, TAPS proposes that TRM set-asides should be conditioned on inclusive reserve-sharing arrangements, with the reservations determined by the reserve-sharing group, subject to dispute resolution before the Commission (and, eventually, approval by joint planning groups).

269. PNM–TNMP suggests that the Commission consider definitions to include the following clarification taken from WECC procedures on ATC: ''If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes.'' [176] PNM–TNMP states that this would allow the transmission provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

270. Nevada Companies argue that no new standards are required for TRM and that any further action would be burdensome. They explain that NERC has a well-established definition that does not require further clarification. In their view, all that is required is a complete statement, to be posted on OASIS, regarding the transmission provider's application of TRM. NERC

[173] The MOD–008 and MOD–009 reliability standards document regional TRM methodologies and procedures for verifying TRM values.

[174] *E.g.*, Allegheny, APPA, EEI, EPSA, Exelon, LPPC, MidAmerican, NRECA, Northwest IOUs, NorthWestern, Occidental, Pinnacle, Powerex, PNM–TNMP, PPL, PJM, PPM, and WestConnect.

[175] Exelon recommends that the following factors should be the same for the planning process and ATC/AFC process to achieve consistency: base case flows, reservation impacts, TRM and CBM forecasted to occur simultaneously; counterflows; positive impacts resulting from reservations and generation dispatch; TRM for the same scenarios; and CBM.

[176] *Citing* WECC Rocky Mountain Operating and Planning Group, *Determination of Available Transfer Capability within the Western Interconnection, June 2001, page 9, http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=1035.*

comments that the existing reliability standards for TRM will be revised to require clear documentation of the calculation of TRM. It also adds that the revised standard will make various TRM components mandatory to achieve more consistency across methodologies.

271. Santee Cooper urges the Commission to ensure that service to native load and transmission system reliability will not be compromised as the Commission seeks greater levels of consistency in the calculation of ATC. It states that the Commission also must be cognizant of the importance of TRM in the provision of service to native load.

Commission Determination

272. The Commission adopts the NOPR proposal and requires public utilities, working through NERC, to complete the ongoing process of modifying TRM standards MOD–008 and MOD–009. We understand that the standard drafting process is underway as a joint project with NAESB.

273. The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process. Transmission providers may set aside TRM for (1) Load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, (6) automatic sharing of reserves, and (7) other uncertainties as identified through the NERC reliability standards development process. Because load, facility loading and other uncertainties constantly deviate, we will not require that TRM set aside capacity be set at zero in the non-firm ATC calculation. In other words, we will not require transfer capability that is set aside as TRM to be sold on a non-firm basis. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM.

274. We will not adopt PNM-TNMP's proposal regarding use of set aside transfer capability as TRM beyond 59 minutes, rather than converting it to CBM. Our proposal is to separate transfer capability set asides as either CBM or TRM without regard to duration of use of the set aside. Therefore, such a clarification is not necessary.

275. In addition, we direct public utilities, working through NERC, to establish an appropriate maximum TRM. One acceptable method may be to use a percentage of ratings reduction, *i.e.*, model the system assuming all facility ratings are reduced by a specific percentage. This is a relatively simple method and, if adopted as the reliability standard's method, should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability.

276. Because of the operational characteristics of the uncertainties that are to be accommodated using TRM, and their aggregate impact on reliable operation, we require each transmission provider to calculate, and allocate on the paths and flowgates, the aggregate TRM value for all LSEs within its area. We support NERC's plan to revise existing reliability standards for TRM to require clear documentation of the TRM calculation, as we expect the TRM value to be supported and fully transparent. In addition, we require each transmission provider to make available all underlying documentation, including work papers and load flow base cases, used to determine TRM, to any transmission customer and LSE within its control area, subject to a confidentiality agreement,[177] if necessary. We agree with Santee Cooper's comments that the Commission must ensure that service to native load and system reliability are not compromised. We believe that our requirement for public utilities to work through NERC satisfies such concerns.

277. With respect to the proposal to permit regional variations in the TRM calculation methodology, we reiterate our position stated above that any request for regional difference from the applicable reliability standards must take place through the NERC reliability standards development process. With respect to TAPS' proposal regarding reserve sharing groups, we clarify that, to the extent transfer capability is needed for transmission of shared reserves, this is included under TRM. However, as noted previously in the CBM discussion, we are not mandating the use of reserve sharing groups.

f. Modeling, Assumptions and Input Data

NOPR Proposal

278. The Commission's proposal with regard to modeling, assumptions and data inputs was based on a principle that there should be consistency among transmission providers and between what the transmission provider does for its operation and expansion planning for native load and what it does in determining short and long-term ATC for all uses. The Commission stated its view that consistency is necessary to ensure non-discriminatory treatment by eliminating a transmission provider's ability to use discretion to the disadvantage of competitors. The Commission proposed three specific areas for reform.

279. First, the Commission proposed to require public utilities, working through NERC, to modify the ATC-related standards to incorporate a requirement for periodic validation and modification of models to ensure that they are up to date.[178] The Commission stated that the models should be updated and benchmarked to actual events.

280. Second, the Commission proposed that, to the maximum extent practicable, the same data must be used by the transmission provider to determine short- and long-term ATC as those used in system operation and planning studies, respectively.

281. Third, the Commission proposed that public utilities, working through NERC, develop assumptions for use in ATC determinations and that the assumptions remain consistent among transmission providers to the maximum extent practicable. The Commission indicated that short- and long-term ATC calculations should be developed using consistent assumptions regarding representative load levels, generation dispatch, transmission reservations and counterflows, in addition to any other modeling assumptions identified by NERC. The Commission further proposed that there should be a consistent approach to the modeling of load levels, a method established for determining which generators should be modeled in service (including guidance on how independent generators should be considered), consistency in the simulation of power flows from points of receipt to delivery when sources are unknown, and consistency in the manner in which ATC/AFC reservations are accounted for. The Commission stated that the model for long-term ATC should include, to the maximum extent practicable, the same assumptions regarding new transmission and generation facilities additions and retirements as those used in planning for expansion.

282. The Commission noted that the proposal is not intended to change the manner in which native load is served

[177] The agreement may appropriately restrict the sharing of sensitive information with customer personnel that are involved only in transmission functions, as opposed to merchant functions.

[178] The Commission noted that this would include review of load flow base cases, short circuit data, transient and dynamic stability simulation data, contingency (files should contain information on special protection schemes and remedial action plans) subsystem and monitoring files, and production cost models.

and sought comment on whether (and, if so, how) this proposal would affect service to native load customers.

Comments

283. Commenters generally discuss consistency of data, assumptions and modeling together so we in turn do the same. Many commenters support the proposals for consistency in data, assumptions and/or modeling.[179] Others support flexibility or regional variation.[180] A few commenters oppose specific aspects of the overall proposal.[181]

284. TDU Systems and Sacramento express support for the Commission's proposal to require public utilities, working through NERC, to develop modeling assumptions for use in calculating ATC that are consistent with those used to plan the operation and expansion of the transmission system. Xcel, however, would have the Commission go further. Xcel recommends that the Commission enhance its proposal by establishing a date certain for transmission providers in the Western Interconnection to be required to account for impacts of loop flows when processing transmission service requests and calculating ATC. Xcel suggests that NERC be directed to develop standards for evaluation of counterflows on ATC. EPSA offers examples of specific data inputs that, in its view, should also be standardized among all transmission providers, which include: Load levels and distribution studies; transmission outages; generation outages; and generation dispatch. Ameren submits that any modeling of base generation dispatch must model generators, including merchant generators, as they are expected to run.

285. Williams asks the Commission to require consistency between transmission planning horizon and procurement terms, and transparency around the long-term transmission planning assumptions. Williams states that third-party bids to a request for proposals are evaluated with transmission costs that may already be included in long-term transmission plans. Thus, argues Williams, procurement and long-term planning assumptions are intertwined. In reply, Entergy acknowledges and agrees that the models used for planning, operations and service request evaluations should generally be based on similar data and procedures, but argues that due to changes in system configuration, facilities included in transmission plans are often not needed at all and thus are not constructed. Therefore, Entergy proposes that the Commission allow NERC to determine the circumstances under which differences between models would be appropriate.

286. Southern asks for clarification on what the Commission intends by proposing that modeling assumptions be consistent in the context of TTC assessments. Southern explains that, as the Commission has recognized, the inevitable changes in system conditions between different time horizons (*e.g.,* real-time and planning and operations) would render this approach unreliable because load levels, dispatch arrangements, reservations, and outages cannot be the same over significantly different time horizons.

287. Supporting regional differences, Bonneville contends that calculating ATC for a hydroelectric system requires different inputs and modeling assumptions than are appropriate for thermal-based systems. Bonneville explains that non-power constraints placed on hydroelectric projects that were built for multiple uses are a major concern on the Bonneville system. Consequently, hydro operators are more limited in their ability to use generation redispatch as a tool to meet long-term firm load obligations. Similarly, Santee Cooper cautions that over-standardization may result in certain parameters being misstated or inappropriately constrained, resulting in inaccurate reservations of capacity for native load purposes and a potentially detrimental effect on the reliability of service. It recommends that the Commission direct NERC to allow deviations from the standard modeling assumptions where the need can be supported, with the caveat that a utility's modeling assumptions must be transparent and available for scrutiny. Seattle contends that modeling assumptions should be developed at the sub-regional level, consistent among adjacent transmission providers. TVA suggests that the transmission providers be allowed to retain flexibility to conduct risk analyses and reflect those in their modeling assumptions.

288. Other commenters argue that modeling assumption standardization should not be performed by NERC and, instead, should be delegated to the regional reliability organizations or RTOs, as they possess a superior knowledge of the physical grid within their boundaries.[182] PJM states that such issues are best left to the joint stakeholder processes and the resulting joint and common market initiatives.

289. In response to the Commission's inquiry as to how standardizing the modeling assumptions and data would affect native load, commenters generally state that standardization of ATC modeling assumptions would increase comparability of service to LSEs and enhance the ATC methodology and its nondiscriminatory application to grid utilization.[183]

Commission Determination

290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD–010 through MOD–025 [184] to incorporate a requirement for the periodic review and modification of models for (1) Load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.

291. We note that commenters generally were very supportive of the Commission's proposals for review and update of models and for consistency of assumptions and data inputs. We received no adverse comments concerning our general proposal to require public utilities, working through NERC, to modify the ATC-related standards to incorporate a requirement for the periodic review and modification of models to ensure that they are up to date. Moreover, the need to improve the quality of system modeling was one of the U.S.-Canada Power System Task Force recommendations.[185]

292. The Commission also adopts the NOPR proposal to require transmission providers to use data and modeling assumptions for the short- and long-term ATC calculations that are consistent with that used for the

[179] *E.g.*, APPA, Arkansas Commission, Constellation, Entegra, Exelon, EPSA, ISO/RTO Council, LDWP, MidAmerican, Municipals, NRECA, CREPC, Sacramento, Santee Cooper, Suez Energy NA, TAPS, TDU Systems, WestConnect, and Williams.

[180] *E.g.*, Bonneville. Santee Cooper, and Entergy.

[181] *E.g.*, PJM, EPSA, and Ameren.

[182] *E.g.,* Sacramento, Manitoba Hydro, Nevada Companies, and TANC.

[183] *E.g.,* Sacramento.

[184] The MOD–010 through MOD–025 reliability standards establish data requirements, reporting procedures, and system model development and validation for use in the reliability analysis of the interconnected transmission systems.

[185] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.*

planning of operations and system expansion, respectively, to the maximum extent practicable. This includes, for example: (1) Load levels, (2) generation dispatch, (3) transmission and generation facilities maintenance schedules, (4) contingency outages, (5) topology, (6) transmission reservations, (7) assumptions regarding transmission and generation facilities additions and retirements, and (8) counterflows. We find that requiring consistency in the data and modeling assumptions used for ATC calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties. The Commission directs public utilities, working through NERC, to modify ATC standards to achieve this consistency.

293. With regard to EPSA's request for the standardization of additional data inputs, we believe they are already captured in the Commission's proposal as adopted in this Final Rule. Xcel asks the Commission to require consistency in the determination of counterflows in the calculation of ATC. Counterflows are included in the list of assumptions that public utilities, working through NERC, are required to make consistent. We believe that counterflows, if treated inconsistently, can adversely affect reliability and competition, depending on how they are accounted for. Accordingly, we reiterate that public utilities, working through NERC and NAESB, are directed to develop an approach for accounting for counterflows, in the relevant ATC standards and business practices. We find unnecessary Xcel's request that we require a date certain for specific issues in the Western Interconnection to be addressed. Above we require public utilities, working through NERC, to modify the ATC standards within 270 days after the publication of the Final Rule in the **Federal Register**.

294. With regard to Williams' request that the Commission require consistency between transmission planning horizons and procurement terms, we believe that such an express requirement is neither appropriate nor necessary. The manner in which transmission providers procure power for native load customers is generally outside the scope of this rulemaking. This notwithstanding, we note that by this Final Rule, Williams and other affected market participants will have an opportunity to participate in a transmission provider's coordinated, regional planning process. This will provide a vehicle for interested parties to gain access to planning-related information and to have their own plans for transmission evaluated at the same time the transmission provider plans for its needs. Coupled with the modifications to the ATC-related reliability standards that require the same data and assumptions to be used for calculating long-term ATC as in system planning, these reforms are adequate to address Williams' concern. To the extent there are changes on the system, these should be captured in the regional transmission planning process and in the determination of ATC. We therefore reject Entergy's proposal to allow NERC to determine the circumstances under which differences between models would be appropriate in order to ensure comparable service for all transmission customers.

295. We offer the following clarifications. In response to Southern, we clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis or approach to determining load levels. For example, one approach may be for transmission providers to calculate load levels using an on- and off-peak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice of approach, it is imperative that all transmission providers use the same approach to modeling load levels to enable the meaningful exchange of data among transmission providers. Accordingly, we direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD–001 for the services offered under the *pro forma* OATT.

296. With respect to modeling of generation dispatch, we direct public utilities, working through NERC, to develop requirements in NERC's MOD–001 reliability standard specifying how transmission providers shall determine which generators should be modeled in service, including guidance on how independent generation should be considered. We agree with Ameren that any modeling of base generation dispatch must model generators, including merchant generators, as they are expected to run. Accordingly, we direct public utilities, working through NERC, to revise reliability standard MOD–001 by specifying that base generation dispatch will model (1) All designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.

297. Regarding transmission reservations modeling, we direct public utilities, working through NERC, to develop requirements in reliability standard MOD–001 that specify (1) A consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.

298. In response to commenter requests in favor of flexibility and regional differences, we again require that any waivers from the approved NERC reliability standards must take place through the NERC reliability standards process as a request for regional difference. Also, we disagree with commenters who argue that modeling assumptions should be delegated to regional reliability organizations. The goal of this rulemaking is to increase consistency in ATC calculations and that is best accomplished through NERC, which has established processes to address requests for regional differences from the reliability standard requirements. We conclude that the NERC process is appropriate as it is open to all industry participants and, therefore, is a suitable arena for establishment of common standards for modeling assumptions.

g. ATC Calculation Frequency

NOPR Proposal

299. The Commission proposed the development of standards requiring that the ATC calculation be performed with consistent frequency among transmission providers. Specifically, the Commission proposed that transmitting public utilities, working through NERC and NAESB, develop standards requiring that the calculation be performed by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. The Commission also supported uniform updating of ATC values and its components (*e.g.*, TTC, ETC, CBM, and TRM).

Comments

300. Alcoa and Powerex emphasize the critical need for ATC to be calculated more frequently for

constrained facilities. On constrained paths, where transmission equipment is stressed to its limits, Alcoa recommends that ATC be calculated on an hourly or real-time basis and be adjusted for temperature extremes. Seattle comments that ATC should be updated on a ''by exception'' basis, *i.e.*, when significant model changes or confirmations of service requests occur. While supporting the Commission proposal, TAPS cautions against updating ATC/AFC too frequently, as this may play into the hands of those who use reservation computer programs.

Commission Determination

301. The Commission adopts the NOPR proposal and requires the development of reliability standards that ensure ATC is calculated at consistent intervals among transmission providers. The Commission thus directs public utilities, working through NERC and NAESB, to revise reliability standard MOD–001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, *e.g.*, generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities. ATC-related requirements for OASIS posting are discussed below.

h. Data Exchange

NOPR Proposal

302. The Commission proposed the development through NERC of standard protocols that would enable and require the exchange of data and coordination among transmission providers. The Commission proposed that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification. The Commission expressed its view that significant improvements in the communication, coordination, and exchange of data across all transmission providers in an interconnection are needed to produce accurate determinations of ATC. The Commission sought comment as to how much data sharing is workable, whether there are additional data that should be provided, whether access to such data should be limited to transmission providers, and if there are existing forums by which these or similar data are already shared.

Comments

303. Most commenters support the Commission's proposal to establish rules for data exchange, but express a preference for confidential data exchange.[186] NERC states that proposed changes to its existing modeling standards would require transmission providers to coordinate the calculation of TTC/ATC/AFC with others. TVA emphasizes that it has already incorporated these principles into its operating processes by executing agreements that provide for data exchange and coordination with neighboring transmission systems.

304. PJM suggests that the data exchange protocols be developed as minimum requirements and not interfere with existing protocols that PJM has with neighboring control areas under agreements such as the MISO/PJM JOA.[187] Similarly, SPP states that it also has developed seams coordination agreements with adjoining transmission providers [188] that fully meet and, in some cases exceed, the Commission's objective of fostering greater data exchanges between transmission providers.

305. MISO is concerned that the NOPR does not address transparency and regional coordination issues arising at the seams between RTO and non-RTO regions, particularly with respect to ATC calculations. In MISO's view, the Commission-approved joint operating agreements between various ISOs and RTOs contain cutting edge ATC calculation methodologies, while no comparable common protocols have evolved with non-RTO utilities. In its reply comments, Exelon agrees with MISO that the various joint operating agreements are not consistent. Exelon proposes that the NERC standards specify requirements for coordination and the type of data that must be exchanged and used for accurate ATC calculations. Exelon contends that having uniform standards for coordination developed by NERC will enhance efficiency throughout the industry, particularly between and among RTO and non-RTO areas. MidAmerican reiterates that ATC coordination remains an issue for RTOs and that any improvements in ATC coordination resulting from this proceeding must apply to the OATTs of RTOs and non-RTOs alike.

306. NAESB states that coordination and data exchange may require business practices for existing transmission reservations, including counterflows, ATC calculation frequency, and source/sink modeling identification. Some commenters request that the Commission clarify that only information necessary for purposes of ATC modeling needs to be exchanged.[189] In particular, they propose that proprietary generation or market information data that might harm their competitive position should not be publicly disseminated since that would not enhance the ability of transmission providers to accurately calculate ATC.

307. While acknowledging these confidentiality and commercial sensitivity concerns, other commenters recommend that the availability of shared data not be limited to transmission providers.[190] For example, TAPS explains that transmission dependent utilities need an opportunity to access the data periodically as a check on the process. To address confidentiality or standards of conduct concerns, TAPS proposes that transmission dependent utilities' access to data could be achieved through an employee barred from disclosing information to marketing staff or a third party independent consultant retained by the transmission dependent utility. However, APPA and Seattle urge the Commission to eliminate artificial and institutional barriers to the exchange of data and information.

308. APPA and Seattle also contend that, even if data were openly available, the vast quantities of hourly data points are difficult to manage, process and analyze using existing methods. To address this issue, APPA recommends

[186] *E.g.*, Allegheny, Ameren, Arkansas Municipal, Bonneville, Constellation, CAISO, Entergy, Exelon, FirstEnergy, LPPC, MidAmerican, Santee Cooper, Seattle, and TAPS.

[187] Under the PJM/MISO Joint Operating Agreement (JOA) and other operating agreements modeled on that agreement, parties have developed comprehensive data exchange protocols to facilitate coordination and consistent AFC calculations. Much of this data is supplied through industry standard sources such as NERC SDX and NERC eTags.

[188] SPP has developed seams agreements to exchange ATC data and coordinate congestion with non-RTO neighbors such as the Southwest Power Administration. Further, SPP exchanges ATC/AFC data and coordinates planning, reserve sharing, outage coordination, and transmission service administration under a transmission coordination agreement with Associated Electric Cooperative, Inc. (AECI), an individual transmission provider situated on SPP's border that is not a member of SPP or any other RTO.

[189] *E.g.*, Allegheny, Constellation, and Indianapolis Power.

[190] *E.g.*, APPA, Bonneville, TAPS, and Seattle.

that the Commission encourage ongoing efforts to obtain greater resolution of system-model State variables, contractual uses and probabilistic ranges and to refine data management and analytical methods.

309. New York Commission suggests having an overarching entity, such as a Transmission Oversight Center, that is responsible for calculating and coordinating ATC between various ISOs/RTOs could overcome this lack of data.

Commission Determination

310. The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices. The following data shall, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) Load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times; and (7) source/sink modeling identification. The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others and this requires a standard means of exchanging data.

311. While there is a near consensus among commenters that significant improvements in the communication, coordination, and exchange of data across all transmission providers are needed to produce accurate determinations of ATC, we acknowledge the concerns of ISO/RTOs that new data exchange protocols may interfere with the existing protocols and seams coordination agreements. Although we will not provide a blanket exemption for ISOs and RTOs from meeting or exceeding the data exchange requirements of this Final Rule, they may, as explained in section IV.C.2, demonstrate in relevant filings that their existing data exchange protocols are consistent with or superior to those that are developed in the NERC and NAESB processes.[191]

312. With respect to concerns regarding the exchange of data that may be a subject of confidentiality and commercially sensitive, we only require information necessary for purposes of ATC modeling to be exchanged. As suggested by some commenters, proprietary generation or market information data that might harm a competitive position should not be publicly disseminated, since that would not enhance the ability of transmission providers to accurately calculate ATC. If any of the data are subject to confidentiality and are commercially sensitive, they must be disclosed in accordance with a confidentiality agreement.

2. Transparency

a. OATT Transparency

(1) Attachment C

NOPR Proposal

313. In the NOPR, the Commission proposed to require each transmission provider to include in Attachment C of its OATT more descriptive information concerning its ATC/AFC calculation methodology. Specifically, the Commission proposed to require the transmission provider to state its specific mathematical algorithm used to calculate firm and non-firm ATC/AFC for its scheduling horizon, operating horizon, and planning horizon. The Commission also proposed to require transmission providers to provide a process flow diagram that illustrates the various steps through which ATC/AFC is calculated. In addition, the Commission proposed to require transmission providers to provide definitions and explain in detail how TTC, ETC, AFC, TRM, and CBM are calculated for both operating and planning horizons.

Comments

314. Most commenters support the Commission's overall proposal on transparency in ATC calculations.[192] Numerous commenters support the Commission's proposal to require detailed information in Attachment C regarding the transmission provider's ATC/AFC calculation methodology.[193] Barrick agrees in its reply comments that a thorough explanation of how ATC is calculated should be made readily available either in the transmission provider's OATT or on its OASIS, thereby improving transparency and making it less difficult for customers to determine whether the calculations are unduly discriminatory. Old Dominion calls for greater transparency in the details of calculating ATC, even as applied to RTOs such as PJM because of the relevance of ATC at the borders of an RTO/ISO and the market impact of inconsistencies in definitions, data, modeling assumptions and frequency of ATC calculations. NERC states that the revised NERC reliability standards will address transparency.

315. NARUC contends that understanding ATC calculation methodologies and having access to the underlying data is essential to a range of critical State commission functions and, therefore, greater transparency of ATC information will significantly enhance State commissions' abilities to fulfill their statutory obligations. On reply, North Carolina Agencies agree with NARUC and state that efforts aimed at increased transparency of ATC calculations should help uncover any actual discriminatory behavior by transmission providers, provide a clearer standard against which to evaluate claims of unduly discriminatory activities, and facilitate regional planning efforts. Entegra states on reply that transmission providers should be required to post narratives explaining changes in models and factors underlying ATC and AFC values, which would be invaluable to the Commission and customers in identifying problems that may warrant enforcement actions.

316. While APPA generally supports the Commission's proposal, some of APPA's members along with other commenters express concern that including all the information might be too burdensome and result in numerous tariff changes.[194] Some APPA members in the West also express concerns about the competitive implications of

[191] We are not requiring that every transmission provider follow identical protocols. Rather, all transmission providers must meet the relevant NERC reliability standards and NAESB business practices, and each entity will be subject to reliability standards compliance audits through which they will have to demonstrate that they meet or exceed the reliability standards.

[192] *E.g.*, Alberta Intervenors, AWEA, Bonneville, CAISO, Constellation, Duke, East Texas Cooperatives, ELCON, Entergy, Entegra, EPSA, E.ON, Exelon, MidAmerican, Morgan Stanley, Municipals, Nevada Companies, NPPD, PGP, PJM, Powerex, CREPC, Santee Cooper, TVA, TAPS, and TDU Systems.

[193] *E.g.*, Arkansas Municipal, Arkansas Commission, CAISO, Constellation, ELCON, Entergy, ISO New England, Morgan Stanley, NARUC, Nevada Companies, Occidental, PJM, Powerex, Project for Sustainable FERC Energy Policy, Santee Cooper, and Suez Energy NA.

[194] *E.g.*, EEI, PNM–TNMP, Sacramento, Seattle, and Southern.

providing such confidential and sensitive information.

317. EEI also notes that providing additional detailed information in Attachment C would be duplicative and may result in confusion due to inconsistencies between the wording of the NERC and NAESB ATC documents and each transmission provider's Attachment C. To avoid uncertainty, EEI recommends that the Commission require transmission providers to comply with the requirements of Attachment C by referencing NERC reliability standards or business practices that provide the information that is called for in the Attachment. MidAmerican believes that additional information concerning calculating ATC and its components would best be retained in the transmission provider's business practices rather than Attachment C. In its reply comments, Powerex suggests an alternative of permitting transmission providers to provide a general reference to NERC, WECC, or NAESB standards and fully outline core definitions, processes, data and assumptions when deviating from such standards.

318. Southern contends that the transparency concerns expressed in the NOPR are driven more by the complexity and volume of the data involved rather than a lack of information. Southern suggests that sufficient information is readily available and the best course of action by the Commission would be to focus on documenting transfer capability methodologies available to transmission customers. NRECA replies that many commenters provided input into why more transparency is needed and repeats the example provided in its NOI comments of a cooperative that spent many months in discussions with a public utility transmission provider in an effort to understand ATC-related information posted on OASIS.

319. Pinnacle contends that the Commission's proposal for detailed information in Attachment C is only relevant in flow-based systems, pointing out that in the Western Interconnection, the scheduling horizon, and the operating horizon are the same and thus reporting such information is not necessary. APPA and Bonneville believe that adding such detail in Attachment C may only result in incremental changes and suggest that better regional coordination would provide greater transparency.

320. Though ISO New England believes this proposal would not create an undue burden, it urges the Commission to allow for variety in the illustration of the process flow diagram. Regarding the proposal to require a ''detailed explanation'' of the calculation of ATC, TTC, ETC, and TRM components, ISO New England argues that the relevant inputs can change on a daily basis because ATC for Pooled Transmission Facilities (PTF) in New England is a function of market conditions, as opposed to an administratively-derived calculation. In ISO New England's view, the level of detail required should reflect the operation of competitive markets. MISO is concerned that the NOPR does not address transparency and regional coordination issues arising at the seams between market and non-market areas, particularly with respect to ATC calculations.

321. MidAmerican strongly urges the Commission to ensure that non-public utility transmission providers adhere to the transparency requirements, since in the Pacific Northwest many of the ''backbone'' transmission lines are co-owned by jurisdictional and nonjurisdictional entities. A jurisdictional co-owner may be limited in its ability to determine such parameters as TRM and CBM because it may not be the line operator. LPPC, in its reply comments, believes it is unnecessary and redundant to require non-public utility transmission providers to adopt the ATC requirements of the *pro forma* OATT, because the Commission recognizes in the NOPR that NERC and NAESB are currently drafting standards for ATC, which when final will be filed with the Commission and become part of the ERO's mandatory reliability standards and fully applicable to otherwise nonjurisdictional entities.

322. Suez Energy NA contends that it is essential that the Commission include an explanation of each component of the ATC calculation in Attachment C to ensure that the transmission provider incorporates NERC standards appropriately and to ensure proper enforcement in the event that an audit shows that the transmission provider has employed other methods of calculating ATC. Suez Energy NA also notes that the mathematical algorithms and process flow diagrams should be provided to users of the transmission system, independent monitors, transmission coordinators and regulators, even if a confidentiality agreement is required. APPA suggests that the Commission and regional reliability organizations conduct additional audits to ensure that these posted practices and procedures are in fact being followed, and that the data used are verifiable.

Commission Determination

323. The Commission adopts the NOPR proposal to increase transparency regarding ATC calculations by requiring each transmission provider to set forth its ATC calculation methodology in its OATT. Each transmission provider must, at a minimum, include the following information in Attachment C to its OATT. It must clearly identify which of the NERC-approved methodologies it employs (*e.g.*, contract path, network ATC, or network AFC). It also must provide a detailed description of the specific mathematical algorithm the transmission provider uses to calculate firm and non-firm ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon). In addition, transmission providers must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation. Furthermore, transmission providers must set forth a definition of each ATC component (*i.e.*, TTC, ETC, TRM, and CBM) and a detailed explanation of how each one is derived in both the operating and planning horizons. Requiring transmission providers to file a statement of their ATC calculation methodology along with a process flow diagram and more detailed definitions of ATC components in Attachment C of the OATT will provide greater transparency to transmission customers and assist in identifying any discrepancies that may arise in ATC determinations. These new requirements will assist in alleviating any appearance of discrimination in the determination of ATC.

324. The Commission acknowledges NARUC's comments that understanding ATC methodologies and the underlying data also will enhance State regulators' ability to meet their regulatory obligations. More transparent ATC calculations are critical to coordinated regional transmission planning that ultimately will improve transmission access for customers and enhance grid reliability. Transparent ATC calculations facilitate the ability of market participants and regulators to detect discrimination.

325. We do not believe our requirement to include additional information in Attachment C will be overly burdensome or lead to an excessive level of future tariff revisions. Attachment C must provide an accurate documentation of processes and procedures related to the calculation of ATC, not the actual mathematical algorithms themselves, which should be

posted on the transmission provider's Web site. These processes define service availability and, as such, must be part of the transmission provider's OATT. It is entirely appropriate that, because revisions to such processes impact transmission availability, they should be filed for Commission approval and included in a transmission provider's OATT. We also require transmission providers to file a revised Attachment C to incorporate any changes in NERC's and NAESB's revised reliability standards and business practices related to ATC calculations, as requested by the Commission in this Final Rule. This filing should be made within 60 days of completion of the NERC and NAESB processes. As we expect transmission providers to rarely change their ATC calculation methodologies, we do not believe this requirement will trigger an unacceptable level of tariff filings modifying the Attachment C description of the ATC components and processes.

326. We agree with ISO New England that the process flow diagram requirement may be met with a variety of illustrations, so long as it is of sufficient detail to provide the transmission customer with a reasonable understanding of the transmission provider's ATC calculation processes. The process flow diagram should support the other Attachment C requirements. As noted above, we agree with Suez Energy NA that mathematical algorithms and process flow diagrams should be made available. We do not find that a confidentiality agreement is generically warranted; however, we note that, a transmission provider may require a confidentiality agreement for CEII materials, consistent with our CEII requirements, or may otherwise protect the confidentiality of proprietary customer information.

327. We also require transmission providers to document their processes for coordinating ATC calculations with their neighboring systems. This requirement is particularly important with respect to seams between market and non-market areas, as identified by MISO, and with respect to the request of other commenters to increase regional coordination regarding ATC calculation. While this Final Rule does not address all seams issues between market and non-market areas, it does take important steps towards that end by improving data exchange between transmission providers and providing increased transparency with respect to ATC calculation.

328. We reject proposals to address the transparency of ATC methodology by merely referencing business practices and reliability standards developed by NERC, NAESB, and WECC.[195] ATC calculations have a direct and tangible effect on the granting of open access transmission service.[196] As such, an accurate and detailed statement of the methodology and its components that defines how the transmission provider determines ATC belongs in the transmission provider's OATT as the means of holding the transmission provider accountable for following non-discriminatory procedures for granting service, not in business practices kept by the transmission provider.[197] However, as noted above, the actual mathematical algorithms should be posted on the transmission provider's web site, with the link noted in the transmission provider's Attachment C.

329. We also reject Pinnacle's assertion that more detailed information in Attachment C would only apply to flow-based systems. Regardless of what type of ATC calculation methodology is employed, transparency in ATC calculations is critical to avoid undue discrimination when allocating transmission capacity under the *pro forma* OATT.

330. In response to MidAmerican's comments regarding the applicability of the ATC-related reforms to non-public utilities, we again refer to section IV.C.3 where we discuss this issue generally. We note here, however, that the ERO's reliability standards currently in development before the Commission will be applicable to all users, owners and operators of the bulk electric grid, which includes non-public utilities.

331. We do not believe ATC-specific tariff audits are necessary to order at this time. The Commission will continue to provide oversight of all tariff-related activities through its enforcement program. Moreover, ATC requirements will be part of the mandatory and enforceable reliability standards and, as such, will be subject to compliance audits through that process.

[195] WECC has on file a Reliability Management System agreement under which transmission providers agreed, through contracts, to follow WSCC reliability criteria. *Western Systems Coordinating Council*, 87 FERC ¶ 61,060 (1999).

[196] The Commission recognized in Order No. 889 that the methodology for calculating ATC and TTC belongs in the tariff. Order No. 889 at 31,607. At the time, the industry represented that it was engaged in efforts to develop uniform methods of determining ATC. The Commission encouraged such industry efforts and required that the tariff include the methodology, which was to be based on current industry practices, standards and criteria.

[197] For the same reason, the Commission disagrees with the assertions of Southern and EEI that more information in Attachment C would be duplicative because some ATC-related information is already available elsewhere.

(2) CBM Practices

NOPR Proposal

332. In the CBM Order, the Commission required transmission providers to post a specific narrative explanation of their CBM practices.[198] In addition, the Commission directed transmission providers to post their procedures for allowing access to CBM during emergencies. The Commission further stated in the CBM Order that, if a utility's practice was not to set aside transfer capability as CBM, it should reflect that in Attachment C.

333. In the NOPR, the Commission proposed to require transmission providers to include this CBM narrative in Attachment C of their OATTs. In addition, the Commission proposed that transmission providers explain their definition of CBM, list the databases used in their CBM calculations, and prove that there is no double-counting of contingency outages when performing CBM calculations.

Comments

334. Seattle and Suez Energy NA support this proposal. Seattle states that CBM information should be specified in Attachment C in order to provide clear guidance for the specific information that is posted on OASIS. Seattle and APPA suggest that CBM should be verifiable and subject to audit by independent parties such as regional reliability organizations.

335. EEI suggests that the Commission revise Attachment C, section 3(f) to replace the word ''prove'' with the word ''demonstrate'' in the requirement that the transmission provider ''prove'' that it does not double count contingency outages when calculating CBM, TTC and TRM. EEI notes that the term ''prove'' implies a determination on the merits after evaluation of competing arguments and evidence. A transmission provider should be able to satisfy its obligations by ''demonstrating'' the absence of a double count. Any customer that wishes to challenge the demonstration can do so, at which time the issue of ''proof'' would arise.

336. With regards to ''double counting,'' TVA references TRM and agrees that additional explanations regarding the calculation of TRM, including methods used to avoid double counting contingency events, should improve transparency in providing open access transmission service. TVA points out that this is being addressed by a NERC standards drafting team.

[198] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶ 61,099 (1999) (CBM Order).

Commission Determination

337. The Commission adopts the NOPR proposal requiring additional information in the transmission provider's OATT Attachment C regarding its determination of CBM. Transmission providers must provide in Attachment C a narrative description detailing their CBM practices. In addition, a transmission provider must explain its definition of CBM and list the databases used to derive its value. These new requirements will provide transmission customers transparency into the CBM component of ATC and help discourage the potential for undue discrimination in the calculation and use of CBM.

338. We adopt EEI's proposal that the Commission revise Attachment C, section 3(f) to replace the word ''prove'' with the word ''demonstrate.'' The word ''demonstrate'' more accurately describes the showing we expect the transmission provider to make. We agree that the word ''prove'' implies a standard of proof that we did not intend to impose. We also acknowledge TVA's comments that the NERC standards drafting team is developing standards that should address ''double counting'' in ATC calculations in general. However, we require that the information in Attachment C be sufficient to demonstrate that a transmission provider is not double counting CBM in its ATC calculation.

339. Finally, the Commission rejects the proposal by Suez Energy NA, APPA, and Seattle to establish formal audits of CBM set asides. Requirements for CBM will be part of the mandatory and enforceable reliability standards and, as such, will be subject to compliance audits through that process. Moreover, the Commission provides oversight of all tariff-related activities through its enforcement program.

b. OASIS

(1) ATC/TTC Posting Requirements

NOPR Proposal

340. The Commission's existing regulations require certain ATC-related information to be posted on each transmission provider's OASIS and other information to be provided on request. To ensure that relevant information is available on a timely basis to all market participants, the Commission proposed in the NOPR to amend its regulations to allow potential customers greater access to information that will enable them to obtain service on a non-discriminatory basis from any transmission provider.

341. The Commission noted in the NOPR that existing regulations require ATC and TTC calculations to be performed according to consistently applied methodologies referenced in the transmission provider's OATT and current industry practices, standards and criteria. The Commission proposed that these calculations be based on the ERO reliability standards.

342. The Commission further proposed to maintain the requirement that transmission providers provide, on request, all data used to calculate ATC and TTC for any constrained paths. Transmission providers also would remain required, on request, to make publicly available any system planning studies or specific network impact studies performed for customers and to post a list of such studies on OASIS.

Comments

343. Several commenters support the proposal to post ATC-related information on OASIS.[199] TDU Systems supports each of the Commission's proposals with respect to providing easier access to data underlying ATC calculations and greater transparency to the process. Sacramento states that posting on OASIS will ensure proper public access, but will avoid the need for Commission approval of an OATT change.

344. Constellation strongly supports the need for additional transparency, stating that providing transmission customers with meaningful insight into the current ''black box'' determination of ATC will help minimize the mystery underlying many transmission provider responses to service requests. According to Constellation, further transparency will assist customers in predicting the outcome of transmission service requests and facilitate increased commercial activity. Constellation suggests that the Commission require transmission providers to provide transmission customers, on request, with specific details related to modeling data, modeling support information, modeling benchmarking and forecasting data, and transmission service request audit data. It requests that the information be in a form and format usable by the transmission customers and that the Commission take steps to ensure that transmission customers understand how ATC is calculated and the data inputs are used to affect those calculations.

345. Great Northern likewise requests that the Commission enhance the requirement to provide all data on request, specifically on constrained paths, by requiring a posted tabulation of annual and monthly ATC calculation details. Great Northern suggests including TTC, network load for each transmission customer, capacity reserved for each network resource, each point-to-point transmission service reservation, CBM and other deductions from TTC.

346. APPA members support the posting of ATC information, as it will assist in using ATC more efficiently, and they support the posting of system planning studies and specific network impact studies that the transmission provider performs for its own merchant function, as well as studies performed for customers. In addition, APPA suggests the posting of facilities studies at the time they become available, assuming that this can be done consistent with CEII concerns. TAPS goes further by urging the Commission to close gaps in the current OASIS requirements by requiring posting of all studies performed for transmission owners' own transmission network resource designations and other uses of the system, including facilities studies as well as system impact studies, ensuring posted study lists are updated contemporaneously with the availability of new studies, and requiring retention of studies for a minimum of five years.

347. Nevada Companies and TVA support cost effective measures that increase transparency in transmission operations and, unless the requirement becomes unduly time consuming or burdensome, in general support more disclosure rather than less.

Commission Determination

348. The Commission adopts the proposal in the NOPR to continue to require transmission providers to comply with existing ATC-related posting obligations as supplemented by this Final Rule. The Commission will continue to require transmission providers, on request, to make available all data used to calculate ATC and TTC for any constrained paths and any system planning studies or specific network impact studies performed for customers. Transmission providers must also continue to post a list of such studies on OASIS.

349. In addition, we agree with the requests of APPA and TAPS to require the additional posting of, at a minimum, a listing of all system impact studies, facilities studies, and studies performed for the transmission provider's own network resources and affiliated transmission customers, to be made available upon request. We note that appropriate procedures to accommodate CEII concerns should be developed to

[199] *E.g.*, APPA, Constellation, FirstEnergy, Indianapolis Power, Sacramento, Suez Energy NA, TAPS, and TDU Systems.

ensure eligible entities with a legitimate interest in transmission study data can receive access to it. Also, we adopt TAPS' suggestion that the studies be made available for five years to make the requirement consistent with data retention requirements pertaining to denial of service requests.

350. The Commission rejects Constellation's and Great Northern's proposals to require transmission providers to provide upon request or regularly post additional information beyond that required in the regulations and this Final Rule. The transmission provider is already required to make available, upon request and in electronic format, all information related to the calculation of ATC and TTC for any constrained path. Accordingly, we see little benefit to require transmission providers to provide upon request or regularly post additional information suggested by these commenters.

(2) CBM/TRM Posting Requirements

NOPR Proposal

351. The Commission's OASIS regulations currently require transmission providers to calculate and post ATC and TTC for each posted path, but make no requirement for CBM and TRM postings. In the CBM Order, however, the Commission required transmission providers, with respect to each path for which the utility already posts ATC, to post (and update) the CBM figure for that path. The Commission also required transmission providers to make any transfer capability set aside for CBM available on a non-firm basis and to post this availability on OASIS. In the NOPR, the Commission proposed to incorporate these CBM posting requirements into its regulations. The Commission also proposed that transmission providers post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM.

Comments

352. Several commenters strongly support the Commission's proposal to require transmission providers to post TRM and CBM.[200] APPA and EPSA agree that the posting of TRM for near term transmission services would provide greater assurance that ATC calculations are being performed according to established procedures. Since transmission providers already have this information, FirstEnergy states that it does not appear to be unduly burdensome for them to post such information. Bonneville indicates that it currently posts TRM values in its Business Practices Forum, which is useful for examining curtailment events, supporting transmission planning objectives, and validating posted ATC values.

353. EPSA also recommends that the Commission provide guidance on standards that should be developed to require each transmission provider to notify the Commission in writing and post a notice on its OASIS within 24 hours of a transmission provider's use of CBM to import emergency power. EPSA also requests that the amount of CBM reserved for each interface be posted on OASIS.

Commission Determination

354. The Commission adopts the CBM posting requirements proposed in the NOPR. In doing so, we amend our OASIS regulations to incorporate the directives established in the CBM Order. Accordingly, we require transmission providers to post (and update) the CBM amount for each path. In addition, the Commission requires transmission providers to make any transfer capability set aside for CBM but unused for such purpose available on a non-firm basis and to post this availability on OASIS. Furthermore, the Commission requires transmission providers to post (and update) the TRM values for the paths on which the transmission provider already posts ATC, TTC, and CBM.

355. We reject EPSA's request to require transmission providers to notify the Commission in writing and post a notice on OASIS within 24 hours of a transmission provider's use of CBM to import emergency power and transfer capability set aside as CBM at each of the transmission provider's interfaces. The additional transparency of CBM-related information provided in this Final Rule, along with the reforms related to consistency of CBM, will cause sufficient information to be made available to customers concerning the use of CBM. The use and allocation of CBM and TRM will be more transparent to transmission customers, thus reducing the potential for undue discrimination.

(3) Periodic Reevaluation of the CBM Set-Aside

NOPR Proposal

356. In the CBM Order, the Commission stated that the level of ATC set aside for CBM can and should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized).[201] The Commission therefore directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the availability of CBM and to post on OASIS their practices in this regard.[202] In the NOPR, the Commission proposed to incorporate these requirements in the Commission's regulations and to obligate transmission providers to reevaluate the CBM set-aside at least quarterly.

Comments

357. Some commenters support quarterly reevaluation of CBM set-asides.[203] TAPS agrees with the need for full transparency of CBM reservations and practices and states that, because CBM values may differ from season to season, CBM values should be separately calculated for at least each quarter. However, TAPS does not find that it is necessary or appropriate for the CBM values to be reevaluated quarterly, given the effort involved in collecting the data and performing the modeling analysis. Rather, CBM studies should be performed at least every other year, supplemented with ''off-year studies'' when appropriate.

Commission Determination

358. The Commission incorporates into its regulations the requirement in the CBM Order for a transmission provider to periodically reevaluate its transfer capability set-aside for CBM. With respect to TAPS' concerns over the effort involved in the re-evaluation process, we will require CBM studies to be performed at least every year. This requirement is consistent with the CBM Order, in which the Commission stated that the level of ATC set aside for CBM should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized).[204] While changes requiring a reevaluation of CBM are longer-term in nature (*e.g.*, installation of a new generator or a long-term outage), quarterly may be too frequent, though two years may be too long and may prevent a portion of the CBM set-aside from being released as ATC. Moreover, annual reevaluation is consistent with the current NERC standard being developed in MOD–005.[205] The requirement to evaluate CBM at least every year also is consistent with the CBM Order in that

[200] *E.g.,* Powerex, PJM, PPL, Seattle, and Pinnacle.

[201] *CBM Order* at 61,237.

[202] *Id.*

[203] *E.g.,* EPSA, Sacremento, Santa Clara, Suez Energy NA, and TDU Systems.

[204] CBM Order at 61,237.

[205] The MOD–005 reliability standard establishes the procedure for verifying CBM values.

the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the need for CBM and to post on OASIS their practices in this regard.

(4) ATC/TTC Narrative Explanation

NOPR Proposal

359. In the NOPR, the Commission proposed to largely retain existing posting requirements for unconstrained posted paths, but to amend the regulations relating to data posted for constrained posted paths. Existing regulations require ATC and TTC on constrained paths to be updated when (1) Transactions are reserved, (2) service ends, or (3) whenever the TTC estimate for the path changes by more than 10 percent.[206] In the NOPR, the Commission proposed to supplement the existing regulations by requiring the transmission provider to post a brief, but specific, narrative explanation of the reason for the change at the time a change in monthly and yearly ATC values on a constrained path is posted. The Commission sought comment on whether the posting of this new information would provide adequate transparency to the customer on a frequent enough basis without imposing an undue burden on the transmission provider. The Commission also sought comment on whether a similar narrative should be required when ATC remains unchanged at a value of zero for some specified period of time.

Comments

360. Some commenters support the Commission's proposal to require transmission providers to post more detailed explanations about changes in ATC values on their OASIS sites.[207] NAESB, TranServ, and Williams request that the Commission clarify the regulatory requirements for posting of updated ATC values such as the level of standardization, frequency and time of postings, and other requirements. CAISO believes that ATC should be updated on a daily basis.

361. Powerex and Nevada Companies propose that additional disclosures be posted, such as data on grandfathered contracts, time-specific data relevant to transmission constraints and ATC rights on posted paths, and remaining customer rights under a reservation-based network service system.

362. A few commenters caution that some of the data that the Commission is requiring to be posted by transmission providers is market-sensitive and, if posted on a real-time basis, could be used by third parties to obtain an unfair competitive advantage.[208] These commenters propose that the transmission providers should be allowed a brief period of delay (*e.g.*, one week) before posting data. Indianapolis Power also advocates a delay due to the burden on transmission providers of the new posting.

363. Several commenters oppose the Commission's proposal to require that transmission providers post narratives on OASIS outlining reasons why monthly and yearly ATC values on constrained paths change.[209] These commenters contend that this will cause undue burden on transmission providers without providing customers with any significant or new information. They also argue that the proposal is impractical and will not result in providing transmission customers with meaningful information regarding transmission service options.

364. If such a requirement is adopted, MISO recommends that a threshold higher than a 10 percent change in ATC be established and that the Commission clarify what the term ''specific explanation'' means in this context. PJM states that it already exceeds the Commission's proposed requirement. However, if strictly applied, this proposal would be unduly burdensome on PJM because it would require PJM to post a narrative each hour. PJM asks that the Commission not apply unnecessary and costly posting requirements on independent RTOs and ISOs.

365. EEI and Southern are concerned that monthly ATC may change in response to every reservation of hourly transmission service because a reservation of hourly firm service on a constrained path may reduce the availability of monthly firm service. EEI contends that, if transmission providers are required to post changes in TTC instead of ATC, they would not be required to post a new narrative every time a reservation is made, thus reducing the overall burden on transmission providers. EEI additionally states that the reasons for changes in TTC and ATC values often are complex and involve the interaction of multiple variables in the model that produces the TTC and ATC values and a specific change in TTC or ATC cannot easily be traced to a specific change in the inputs. Alternatively, EEI suggests that transmission providers could post the major changes in the inputs to the TTC modeling software that are made in connection with each updated TTC posting without ascribing specific inputs to specific changes in TTC and ATC values on specific lines.

366. Several commenters are supportive of the proposed requirement that transmission providers provide a narrative explanation when ATC values remain at zero.[210] APPA suggests that if a particular interface shows an ATC of zero for a specified period, the transmission provider should provide a narrative explanation of why this is the case and how its plans to address this problem. It also suggests that this information should be employed in the transmission planning process. East Texas Cooperatives, in reply comments, state that the narrative can provide useful information to the transmission customers and State and Federal regulators regarding specific conditions regarding ATC coordination.

367. In supplemental comments, NAESB states that the Commission should specify whether it is sufficient for the explanation of changes in ATC or TTC values to be limited to broad generalized statements or whether the posted information should include such information as the specific events which gave rise to the change, the new values for ATC at all points on the network, the impact of the change on transmission customers, and a detailed snapshot of the conditions on the system at all flowgates or constrained elements when the change occurred.[211]

368. Southern states that posting a narrative when ATC remains at zero is unwarranted and unnecessary, as it simply indicates that the market has responded to market signals of ATC availability and purchased all available capacity.

Commission Determination

369. The Commission adopts the NOPR proposal, with the modifications discussed below, to require that the transmission provider post a brief, but specific, narrative explanation of the reason for a change in monthly and yearly ATC values on a constrained path. Rather than requiring a narrative

[206] *See* 18 CFR 37.6(b)(3)(i)(C).

[207] *E.g.,* Arkansas Commission, CAISO, Constellation, East Texas Cooperatives, Exelon, FirstEnergy, LPPC, Morgan Stanley, NRECA, Pinnacle, Powerex, Santa Clara, and Suez Energy NA.

[208] *E.g.,* Ameren, ISO New England, Southern, and NRECA.

[209] *E.g.,* Ameren, EEI, Entergy, MISO, Pinnacle, PJM, PNM–TNMP, Southern, TranServ, and TVA.

[210] *E.g.,* APPA, East Texas Cooperatives, Suez Energy NA, and TAPS.

[211] November 2, 2006, *Addendum to the Testimony of Ronald M. Mucci on behalf of the North American Energy Standards Board,* Preventing Undue Discrimination and Preference in Transmission Service, Docket Nos. RM05–25–000 and RM05–17–000, October 12 Technical Conference, pp. 2–3.

when a monthly or yearly ATC value changes as a result of transactions being reserved, service ending, or the TTC estimate for the path changing by more than 10 percent, we will require a narrative when a monthly or yearly ATC value changes only as a result of a 10 percent change in TTC. This will reduce the number of ATC changes for which a narrative will be required and address concerns that the new requirement unduly burdens transmission providers. Any remaining burden is justified by the benefit to transmission customers of receiving timely information regarding changes in TTC that result in changes to ATC. In addition, we adopt NAESB's suggestion that posted information include the (1) Specific events which gave rise to the change and (2) new values for ATC on that path (as opposed to all points on the network).

370. We reject calls for delays prior to posting data. While commenters allege the possibility of granting others a competitive advantage through the release of ''market-sensitive'' data, they have proffered no evidence to support the allegation of potential harm.

371. We do require, as suggested in the NOPR, a narrative with regard to monthly or yearly ATC values when ATC remains unchanged at a value of zero for a significant period, and will set that period at six months or longer. This information will be valuable to customers and regulators in assessing the ability of a transmission provider's facilities to meet existing service requests. The information also will provide assurance to customers that the transmission provider is diligent in regularly evaluating ATC on all paths, monitoring persistent constraints and addressing them in its planning processes.

372. Finally, we reject CAISO's suggestion that ATC be updated daily on a transmission provider's OASIS site, because CAISO offered no justification for the proposal.

(5) Denial of Service/Records Retention

NOPR Proposal

373. In the NOPR, the Commission proposed to maintain the requirement that a transmission provider post the reason for a denial of a request for service. The Commission also proposed to amend this provision to require a transmission provider to maintain and make available information supporting the reason for the denial. The Commission further proposed to extend the time period for which transmission providers must maintain transmission service information for audit. Currently, regulations require that audit data be retained and made available upon request for download for three years from the date when they are first posted. The Commission proposed to change the period from three to five years.

Comments

374. Many commenters support posting of the reasons for denying service and the 5-year retention proposal.[212] TAPS supports the proposal but suggests several modifications. First, it suggests that the Commission clarify the requirement to post the reasons for denying service is triggered not only by denial of the entirety of a transmission request, but to any disposition that falls short of a full unconditional grant of the service (with rollover rights if applicable). Second, TAPS recommends that the regulatory text of proposed section 37.6(e)(2)(ii) be modified to make the supporting data available, upon request, to any eligible customer rather than just to the customers who were denied service. Third, it asks that the Commission expand its OASIS regulations to require the transmission provider to maintain and make available on request the information supporting the disposition (positive, negative, or in between) of its own network resource designations and other usage needs. East Texas Cooperatives suggest that the Commission also require that transmission providers distinguish between denials of requests for firm and non-firm transmission service.

375. Some commenters urge the Commission to clearly define the scope of any transmission service request information subject to the proposed five-year record retention requirement to ensure that no undue administrative burden is placed on transmission providers.[213] TVA questions the need to extend the time period for an additional two years. TVA states that the benefits of extension are not commensurate with the increased costs, since it is unaware of any problems that have arisen with the current three-year timeline. Seattle argues on reply that the Commission should retain the NOPR posting requirements in the Final Rule because information on actual transmission congestion can be helpful instead of sole reliance on simulation models.

Commission Determination

376. As proposed in the NOPR, the Commission maintains the requirement that a transmission provider post the reason for a denial of service and extends from three years to five years the period for which transmission providers must maintain data providing reasons for denial of service. In general, commenters support the requirement for posting denial of service information and the increase in retention time to five years, indicating that such information can be helpful to customers in their awareness of actual transmission congestion, rather than relying on simulation models.

377. We also adopt TAPS' suggestion to expand the regulations to include availability of information supporting the disposition of a transmission provider's own network resource designations and to make such information available to any eligible customer rather than just to that customer denied service. In addition, we clarify that a partial denial of service triggers the requirements as well. Such information is consistent with the new regulations established by this Final Rule and will help ensure that customers receive transmission service that is not unduly discriminatory. The development of a log of service denials, full or partial, will establish an ongoing record of service requests and transmission provider responses demonstrating the transmission provider's provision of nondiscriminatory open access service. Furthermore, repeated denials of service over a particular path or flowgate will provide an indication of congestion that can be used in the transmission planning process. In addition, we agree with East Texas Cooperatives that postings of denials of service should indicate whether the requested service was firm or non-firm.

(6) Designation and Termination of Network Resources

NOPR Proposal

378. In the NOPR, the Commission proposed to require the transmission provider and network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of a network resource. This information would be posted on OASIS for 90 days and be available for audit for a five-year period. Transmission customers therefore would be able to query such requests to designate and

[212] *E.g.,* APPA, Arkansas Commission, Arkansas Municipal, Duke, East Texas Cooperatives, MISO, ISO New England, Williams, Nevada Companies, PPL, Sacremento, Sant Clara, Suez Energy NA, and TDU Systems.

[213] *E.g.,* MidAmerican, PacifiCorp, PNM–TNMP, and PJM.

terminate a network resource.[214] The Commission also proposed to require the transmission provider to post on its OASIS a list of its current designated network resources and all network customers' current designated network resources. The list would include the resource name, geographic and electrical location and amount of capacity of the designated network resource.

Comments

379. Several commenters support the Commission's proposal to require transmission providers and network customers to use the transmission provider's OASIS to request or terminate designation of resources, though some indicated that the required network resource information is currently available via OASIS.[215] PJM supports the proposal, provided that the electrical location is based on an industry standard format and any standard adopted by NERC takes into consideration possible confidentiality issues when posting the geographic location of designated network resources.

380. APPA suggests that reservations related to future load growth also should be posted so that it is clear to all industry participants what transmission capacity transmission providers are reserving for load growth purposes. Williams submits that the list of current designated resources needs to indicate whether they are for native load or network customers, or whether they are for meeting forecasted loads and system emergencies.

381. TranServ supports the Commission's proposal and indicates that NAESB is the appropriate forum for development of standards necessary to support posting the designation and termination of network resources. TranServ cautions that implementation will require a sufficient period of time after the practices and standards are developed and suggests that changes to OASIS should be timed to avoid peak summer and winter seasons.

382. Exelon requests that the Commission clarify that transmission providers and network customers making firm off-system sales may terminate designation of network resources solely for the term of such sale and not for other periods of time. During this period of termination, the firm capacity is posted and made available to other customers.

383. Great Northern supports the proposal and requests clarification that, when a network resource is ''undesignated,'' ATC will not be set aside in anticipation that it might be designated again as a network resource in the future. Great Northern requests that the Commission confirm that new requests to designate network resources, regardless of the prior designation of those resources, are placed at the end of the transmission service queue.

384. Sacramento states that the posting requirements for network resources are an unnecessary burden and instead recommends that the transmission provider should be required to identify resources it is transmitting to native load when it denies a request for transmission service from a third party.

Commission Determination

385. The Commission adopts the NOPR proposal and requires transmission providers and network customers to use OASIS to request designation of new network resources and to terminate designation of network resources.[216] This information shall be posted on OASIS for 90 days and available for audit for a five-year period. Transmission customers thus shall be able to query requests to designate and terminate a network resource. This requirement adds valuable transparency without undue burden, since it is nothing more than maintaining a database of designation requests made and responded to electronically. The Commission orders public utilities, working through NAESB, to develop appropriate templates for OASIS.

386. The requests for clarifications by Exelon and Great Northern will not be addressed in this section. These requests are not related to OASIS postings, but involve changes in tariff language. They are addressed in section V.D.6 of this Final Rule.

(7) Posting of Unused Transfer Capability

NOPR Proposal

387. In the NOPR, the Commission reminded transmission providers that transfer capability associated with transmission reservations that is not scheduled in real time should be included in non-firm ATC and posted on OASIS.

Comments

388. Entegra, TANC, and TDU Systems emphasize the need for the posting of unused transfer capability. TDU Systems state that the requirement to post on OASIS all transfer capability associated with transmission reservations not scheduled in real time furthers not only the Commission's goals with respect to comparability and transparency of ATC calculations, but also the Commission's goals in freeing up access to transmission capacity for transmission customers.

Commission Determination

389. We affirm our statement in the NOPR proposal acknowledging that transfer capability associated with transmission reservations that are not scheduled in real time is required to be made available as non-firm, and posted on OASIS.

(8) Other OASIS Issues

Comments

390. MidAmerican, PacifiCorp and Pinnacle contend that the development of the OASIS posting requirements is technical in nature and should be addressed by the NERC and NAESB processes.

391. NRECA recommends that the Commission require public utility transmission providers to make OASIS data available in a useable, machine-readable and manipulable format to transmission customers (so they can be better prepared to make decisions about their transmission needs) and to the Commission (so that it can monitor the provision of transmission service). Similarly, Powerex states that posted data must be in sufficient detail to permit third parties to independently review and verify ATC postings and treatment of transmission service requests.

392. Utah Municipals suggest that OASIS sites be as uniform and compatible as possible and reasonably user-friendly, and that certificate fees for access to non-public sites be evaluated for legitimacy. Arkansas Commission and Seattle also express concern over the OASIS access requirements established by most transmission providers, which require viewers to purchase certificates or licenses for the particular computers from which OASIS access is sought.

393. Williams suggests that all transmission service-related business practices and local procedures, including the exercise of discretion or waiver or granting of exception, be posted on the transmission provider's OASIS. It also suggests that real-time data and import/export limits by constrained area should be posted on OASIS, along with line outages

[214] *See* 18 CFR 37.6(a)(6).

[215] *E.g.*, APPA, Exelon, PJM, TAPS, TranServ, and TDU Systems.

[216] *See* paragraph 1477, where further detail on using OASIS to request designation of network resources is provided.

(planned and unplanned), estimated return to service dates and de-rates of a line.

Commission Determination

394. In response to NRECA and other commenters regarding the availability and format of data available on OASIS, we note that current regulations already require that OASIS data be made available in a useable, machine-readable user friendly format to transmission customers. The improvements required in the Final Rule will enhance the level of detail posted on OASIS and, in turn, transmission customers' ability to verify the transmission provider's treatment of transmission requests. Thus, to the extent NRECA or others desire greater consistency in data formats, they should propose such revisions through the NERC and NAESB processes.

395. Regarding comments received expressing concern about the use of certificates for OASIS access, we believe that the use of such certificates can be appropriate. However, the Commission reminds transmission providers that the cost of OASIS access, whether by registration, certificate or other form of license, should be limited to a nominal charge, *e.g.*, no more than $100. This nominal fee provides funding for OASIS maintenance while assuring that all transmission customers and potential customers will not be denied access because of excessive fees.

396. With respect to Williams' request for additional OASIS postings, we agree that such additional data would be useful to transmission customers and is already posted on some ISO and RTO Web sites and, to a lesser extent, on the NERC web site (TLR data). Therefore, we require that all transmission service-related business practices and local procedures, including waivers, should be posted on or made available through OASIS. With respect to real-time data and import/export limits by constrained area, estimated return-to-service dates and line de-ratings, we are confident that most of this data is already required by this Final Rule and shall be provided whenever TTC and ATC changes in value trigger the posting of a narrative explanation of the causes of those changes. Moreover, the Final Rule requires a broad data exchange among transmission providers, including information on line outages and other data relating to ATC calculations. Accordingly, we will not require additional OASIS postings for this data.

(9) CEII

NOPR Proposal

397. Critical Energy Infrastructure Information (CEII) is information concerning proposed or existing critical infrastructure (physical and virtual) that (1) Relates to the production, generation, transportation, transmission or distribution of energy, (2) could be useful to a person in planning an attack on critical infrastructure, (3) is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552, and (4) does not simply give the location of the critical infrastructure.[217] Access to such transmission related information has been restricted by the Commission's CEII regulations.[218]

398. In the NOPR, the Commission recognized that the use of the existing CEII processes could undermine their goal of providing increased transparency to information necessary to evaluate the use of the transmission system. As a result, the Commission requested comment on procedures that could be adopted by transmission providers to streamline the resolution of CEII concerns and allow timely disclosure of information from the transmission providers to interested parties.

Comments

399. APPA and other commenters argue that the additional information disclosure requirements proposed in the NOPR raise substantial CEII concerns, and request the Commission to refine its CEII procedures to allow those with legitimate need for the information to obtain it on a timely basis.[219] Bonneville would like to permit public access for stakeholders to review principles and methods used in ATC calculations, but only permit limited access, subject to background checks and non-disclosure agreements, to modeling data that may compromise infrastructure security. APPA suggests establishing a process for advance qualification for receipt of such information by those industry participants with rights to review information on the customer side of OASIS, without giving blanket public access. TDU Systems urge the Commission to adopt a streamlined process to ensure timely resolution of ATC calculation disputes and to adopt measures that ensure that CEII claims do not unduly restrict information.

400. EEI and Southern caution that the release of a transmission provider's explanation of methodologies, practices, and procedures in Attachment C may not give rise to CEII concerns, but that other information such as energy infrastructure data, models and assessments do raise security and confidentiality concerns. They propose that a transmission provider have the ability to seek confidential treatment of such information. Allegheny proposes that an independent third party or Commission staff review and explain ATC calculations to interested parties without disclosing CEII.

401. Several commenters believe that much of the information the Commission proposes to require transmission providers to provide will not pose CEII concerns.[220] However, Entergy states that some of the information requires protection as proprietary information because its public availability over OASIS would reveal commercially sensitive information. ISO New England also points out that information relevant to the ATC calculation may be market-sensitive

402. Pinnacle believes the current CEII process is not unduly burdensome and urges the Commission to continue to apply the existing CEII procedures, which allow transmission customers with digital certificates or passwords to access publicly restricted transmission information.

Commission Determination

403. The Commission acknowledges that certain data and studies required to be made public under this Final Rule may contain CEII. The Commission has a responsibility to protect this information. However, the Commission agrees with APPA, Bonneville, and TDU Systems that those with a legitimate need for CEII information must be able to obtain it on a timely basis. The Commission also shares EEI and Southern's concerns that the data, models and assessments used to calculate ATC may contain information that raises security and confidentiality concerns, and ISO New England and Entergy's concerns about commercial and market-sensitive information.

404. In order to provide transparency and avoid undue delays in providing information to those with a legitimate need for it, the Commission requires

[217] *See Critical Energy Infrastructure Information*, Order No. 683, 71 FR 58273 (Oct. 3, 2006), FERC Stats. & Regs. ¶ 31,228 at P 66 (2006), *reh'g pending*. We note that the Commission is proposing to change the definition of CEII in a proceeding in Docket No. RM06–23–000. *See Critical Energy Infrastructure Information*, Notice of Proposed Rulemaking, 71 FR 58325 (Oct. 3, 2006), FERC Stats. & Regs. ¶ 32,607 (2006).

[218] *See* 18 CFR 388.112–113.

[219] *E.g.*, MidAmerican, Sacramento, Southern, and TVA.

[220] *E.g.*, Nevada Companies, East Texas Cooperatives, PJM, and TDU Systems.

transmission providers to establish a standard disclosure procedure for CEII required to be disclosed by this Final Rule. We note that transmission customers already have digital certificates or passwords to access publicly restricted transmission information on OASIS. Transmission providers may set up an additional login requirement for users to view CEII sections of the OASIS, requiring users to acknowledge that they will be viewing CEII information. Transmission providers may require customers to sign a nondisclosure agreement at the time that the customer obtains access to this portion of the OASIS. Only information that meets the criteria for CEII, as defined in section 388.113 of the Commission's regulations,[221] should be posted in this section of the OASIS. Transmission providers will be responsible for identifying CEII and facilitating access to it by appropriate entities, and the Commission will be available to resolve disputes if they arise.

(10) Additional Data Posting

NOPR Proposal

405. To further reduce discretion in calculating ATC/AFC, the Commission proposed that transmission providers post on OASIS metrics related to the provision of transmission service under their OATT. In the NOPR, the Commission proposed to require the monthly posting of (1) The number of affiliate versus non-affiliate requests for transmission service that have been rejected and (2) the number of affiliate versus non-affiliate requests for transmission service that have been made. This posting would also detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The Commission sought comments regarding whether it should require transmission providers to post their underlying load forecast assumptions for all ATC calculations and, on a daily basis their actual daily peak load for the prior day. Finally, the Commission asked for comment on the overall benefit of posting the proposed metrics, on potential alternative metrics, and on working through NAESB to develop standards for consistent methods of posting the new requirements on OASIS.

Comments

406. PJM and other commenters support the proposal to post data showing acceptances and denials of transmission service requests of non-affiliates and affiliates.[222] However, PJM and Ameren argue that the affiliate posting requirement should not apply to RTOs and ISOs, because they are independent, have no affiliates, and lack incentive to favor one transmission customer over another. MDEA requests clarification on how the additional posting requirements would be applied under Entergy's weekly procurement process. Entergy notes on reply that the Commission has already established metrics to measure the performance of its weekly procurement process, and the creation of further metrics are beyond the scope in a generic rulemaking. Entergy further points out that non-affiliated generating facilities that are designated as network resources to serve native load also benefit from transmission service obtained in this manner. It suggests that NAESB is the best forum for considering such issues and developing specific procedures for calculating these metrics. TranServ suggests that there are other useful metrics that NAESB should be directed to define, such as average time to evaluate requests and confirm requests, and percentage of requests denied, approved and withdrawn.

407. PJM notes its support of proposed OASIS posting reforms, but cautions that all industry groups must have an equitable and proportionate voice in NAESB if it is requested to develop standards. It also expresses concern that PJM and other RTOs have established a practice of posting a significant amount of data for participants' use in formats and applications which respective members have requested and approved through stakeholder processes.

408. APPA points out that the data on transmission denials would be useful to the Department of Energy (DOE) in reporting on congestion in its triennial congestion studies to be prepared under FPA section 216(a), and that NAESB may be able to provide standard formats for disclosure of such data. Some APPA members express a preference for NERC to develop these standards, while others stress the need for regional variation in posting requirements.

409. Ameren questions whether the posting requirement would serve the Commission's objective of identifying undue discrimination even in cases where the transmission provider is not an RTO or other independent transmission provider, because the metrics can lead to incorrect impressions. MidAmerican also states that the proposed posting would require sophisticated analysis to yield useful benefits.

410. EEI is not opposed to the proposal to post metrics on acceptance and denial of requests for transmission service, but suggests such information is already available on OASIS and that any customer or the Commission staff can develop its own metrics. Southern also states that this data is currently available.

411. Several commenters support the posting of forecast and actual daily peak loads.[223] Ameren states that the proposed requirement would produce a useful comparison, increase transparency, and provide the ability to verify that an appropriate amount of capacity is being set aside for native load. E.ON states that RTO and ISO forecasts and actual data need to be posted with sufficient granularity to allow for meaningful comparison of control area and LSE load levels. EEI requests that the Commission clarify that its proposal to require the posting of peak loads applies to system-wide loads and not only to the native load of the transmission provider. It also seeks clarification that the differences between forecast and actual system peak loads not result in any repercussions.

412. APPA members in the East generally favor the proposal to post the load information, but its members in the West expressed concerns about the competitive implications of providing such data. Additional commenters express concern about data confidentiality.[224] TAPS contends that providing for data disclosure on a one-day lag basis would alleviate these commercial concerns, but it also suggests that the Commission should require the disclosure of projected load forecast information on request to a customer's non-market employees or agents.

Commission Determination

413. The Commission adopts the proposed requirement to post on OASIS metrics related to the provision of transmission service under the OATT. Specifically, transmission providers must post (1) The number of affiliate versus non-affiliate requests for transmission service that have been rejected and (2) the number of affiliate versus non-affiliate requests for

[221] 18 CFR 388.113.

[222] *E.g.*, Arkansas Commission, Constellation, MidAmerican, MDEA, Morgan Stanley, Nevada Companies, NRECA, Suez Energy NA, and TranServ.

[223] *E.g.*, Ameren, Constellation, E.ON, Nevada Companies, NRECA, Powerex, Suez Energy NA, TAPS, TDU Systems, and TranServ.

[224] *E.g.*, E.ON, Entergy, LDWP, and TranServ.

transmission service that have been made. This posting must detail the length of service request (*e.g.*, short-term or long-term) and the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The Commission also will require transmission providers to post their underlying load forecast assumptions for all ATC calculations and, to post on a daily basis, their actual daily peak load for the prior day. The Commission directs transmission providers to work through NAESB to develop standards for consistent methods of posting the new requirements on OASIS.

414. The Commission agrees with PJM and Ameren that affiliate posting requirements do not apply to RTOs and ISOs, since they do not have affiliates to transact with. The Commission also agrees with Entergy that the metrics established for its weekly procurement process are outside the scope of this proceeding.

415. In response to Southern's point that the information necessary to compute the metrics is already available on OASIS, while it is true that service denial information is available on OASIS for long periods, request information is not. As such, a customer would need to continuously download information from OASIS to record the data sufficient to calculate the metrics on its own. The Commission concludes that it is not unduly burdensome for transmission providers to calculate the metrics required by this Final Rule.

416. With regard to posting of load forecasts and actual daily peak load, we conclude that such postings are necessary to provide transparency for transmission customers. We agree with E.ON that RTO and ISO load data needs to be posted at a sufficient granularity to allow for meaningful comparison of control area and LSE load levels. Most RTOs and ISOs post load data for the entire footprint, but few post it on an LSE or control area basis. We therefore direct ISOs and RTOs to post load data for the entire 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 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]

[225] *See* Order No. 888–A at 30,311.

[226] *See id.*

[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.

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]

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 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 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 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 EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Electric Transmission Corridors and the Commission's responsibilities under EPAct 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

[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 Web site, *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.

[229] Order No. 888 at 31,682.

[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). 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.

[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).

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, 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 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, 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 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

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

[236] *E.g.,* Duke, Exelon, and Xcel.

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

[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.

[241] *See also* TAPS Reply.

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

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 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 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 EPAct 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 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 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

[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. FMPA and others, however, argue that the Commission does have the authority to order joint ownership. Joint ownership will be discussed more fully below.

[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'').

[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 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.

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 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 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 Web site 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 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

[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.**

[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.

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

[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.

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 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 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 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.

[251] *E.g.,* Nevada Companies and NorthWestern.

[252] *E.g.,* Entergy, Progress Energy, SCE, and Southern.

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

[254] This collaborative approach is also generally supported by East Texas Cooperatives, FMPA, 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.

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 Energy states the Commission should be flexible regarding the composition of meetings and openness, noting that in North Carolina meetings involving CEII 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 confidentially 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 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. 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.

[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.

[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.

[258] *See also* East Texas Cooperatives Reply and NRECA Reply.

[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.

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 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 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 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 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

[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).

[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.

[265] *See also* ISO/RTO Council.

[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

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 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 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 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 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

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.

[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.

[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.

[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 Web sites, 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.

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 be permitted to participate in that process on a comparable basis.[274] This is consistent with EPAct 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.

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 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

[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.*

[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.

[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.

[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.

performed, and how and why proposed upgrades 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. 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-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 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

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

[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.

[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.

[287] *E.g.,* ELCON, New Jersey Board, and WIRES.

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.

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.

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 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 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

[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.

[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.

[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.

[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.

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 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 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 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

[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.

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

[297] *See also* MidAmerican Reply.

[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] *E.g.,* California Commission, Imperial, and Salt River.

[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 participation, because 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 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 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 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.

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

[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.

[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.

[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.

[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.

[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.

yet clear how such groups intend to coordinate with each other.

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.

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, FMPA[311] 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 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 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.

[310] *See also* TDU Systems Reply.

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

[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.

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 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 duplicative of the studies being performed by DOE pursuant to EPAct 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 considering the

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

[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.

[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.

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.

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 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.

[320] *E.g.*, Allegheny, FirstEnergy, Indianapolis Power, and PSEG.

[321] *See also* Indicated Parties Reply.

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 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 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

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

[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.

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 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 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

[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.

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

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.

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 providers have conducted non-transparent processes.[330] Most commenters fall somewhere between these two positions, finding potential benefits in independence but concurring with the proposal not to mandate it.

564. Several public utility commenters acknowledge the potential benefits of using an independent coordinator and believe the Commission should encourage it.[331] National Grid, for example, finds it difficult to see how a non-independent transmission provider would be able to manage confidential information in a manner fair to all stakeholders and recommends finding independent administration of planning ''superior to'' non-independent administration. Other commenters note only that independence can be beneficial or suggest that the Commission be open to independent third parties when offered.[332] Progress agrees there can be benefits, but does not believe an independent coordinator is needed to ensure confidence.

565. EEI argues against an independence requirement, seeing no need to require non-RTO/ISO transmission providers to engage independent third parties to oversee the planning process.[333] EEI believes the

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

[330] *See also* AWEA, Arkansas Commission, Old Dominion, and Project for Sustainable FERC Energy Policy. Old Dominion stresses that even in RTOs, the transmission owners may have the ability to exercise market power and, therefore, the market monitoring unit should have the requisite independence and authority to investigate and address undue influence.

[331] *E.g.,* National Grid, PPL, Constellation, and Tacoma.

[332] *E.g.,* APPA, Bonneville, California Commission, Duke, Indianapolis Power, NCEMC, NorthWestern, Progress Energy, CREPC, Sacramento, Seattle, and TDU Systems. Some public power entities, such as APPA, NRECA, and TDU Systems are concerned with ensuring that the costs of an independent coordinator do not outweigh the benefits.

[333] TVA believes that the levels of independence practiced in NERC and NAESB and the implementation and administration of those

planning processes proposed in the NOPR are adequate without third party oversight and maintains that requiring third party coordination could add another layer of administration, might encroach on State authority, and could create the possibility that the transmission provider would lose control of the transmission plan. EEI however also notes that the Commission could require independent oversight in circumstances where a transmission planner has failed to implement the principles or has engaged in undue discrimination in planning for customer needs.

566. The consensus at the October 12 Technical Conference was generally supportive of the potential benefits of an independent facilitator, but not supportive of a mandate. There was general support for the idea that an independent facilitator can assist with handling sensitive information and provide confidence that analysis of information would be fair, although several participants stated that sufficient trust and confidence could be obtained without an independent facilitator.

Commission Determination

567. The Commission adopts the NOPR proposal to not require the use of an independent third party coordinator at this time. We agree that there are benefits to be gained from independent third party oversight, as cited by commenters, such as the ability to manage confidential information and the ability to ensure equitable treatment of all viewpoints in planning. We therefore encourage transmission providers and their customers and other stakeholders to explore aspects of planning where the use of an independent coordinator would be beneficial and to incorporate those aspects in their planning process compliance filings.

568. It is, however, possible to comply with the principles without the use of an independent third party. We expect the transmission plans themselves to be developed under an open process that includes coordination among each transmission provider, its customers, other stakeholders, and its neighbors. A transmission provider will need to demonstrate to us in a compliance filing that the plan meets the principles, including providing a dispute resolution process. We believe that an open, transparent planning process, with meaningful coordination and dispute resolution, will provide a sufficient basis for customers to identify and raise meaningful concerns if a plan does not treat similarly-situated customers in a comparable manner, where planning appears to be conducted in a discriminatory manner, or in other instances where the independence of planning may be in question. If disputes do arise in these areas and cannot be resolved consensually, we are available to either encourage a consensual resolution (*e.g.*, by use of the Dispute Resolution Service) or resolve them ourselves if a complaint is filed.

b. State Commission Participation

569. In the NOPR, the Commission strongly encouraged the participation of State commissions and other State agencies in the coordinated planning process, particularly with regard to regional planning. The Commission sought comment on how best to accommodate effective State participation.

Comments

570. All commenters addressing the question of State participation agree that states have an important role in transmission planning, but there were only limited comments recommending specific processes to encourage State participation. Supporters of State participation generally believe that it can assist in obtaining siting approval and in cost recovery. ISO/RTO Council and individual RTOs and ISOs point to their current processes for including states in their region in the planning process. Noting the local benefits that can derive from interstate transmission projects, American Transmission supports collaborative efforts among states such as the Organization of MISO States. However, American Transmission and other commenters suggest that the Commission defer to the states to determine how they participate in the planning process.[334]

571. Allegheny believes it should be the responsibility of the transmission provider to maintain good communication with State commissions. Nevada Companies assert that the real question the Commission should be posing is how to coordinate the State jurisdictional role in transmission planning and construction and the obligations imposed by the Commission on transmission providers, so that the system of coordination does not put transmission providers in the middle between conflicting State and Commission requirements. Moreover, Santa Clara notes that some State commissions do not represent all energy consumers, since they are charged only with regulating public utilities, and could be conflicted and disinclined to act in the best interests of entities not under their jurisdiction.

572. NARUC supports active State commission participation in both RTO and non-RTO markets.[335] NARUC asks that the Commission clarify that its planning proposals assume that the results of State commission planning decisions relating to retail load will be incorporated into the planning process rather than subject to further review. NARUC and New Mexico Attorney General also ask for clarification that joint planning will allow for communications between resource and transmission planners for the purpose of developing State-required resource plans and that this will not be considered a violation of the Standards of Conduct. PNM–TNMP and Southern support the NARUC position in their reply comments.

573. New York Commission wants to ensure that the Commission's planning responsibilities cover only transmission that serves a bulk power system function.[336] Florida Commission believes that it already has direct oversight of grid planning and related issues, through among other things its participation in the FRCC planning process and review of the annual Ten Year Site Plan. Seattle does not believe that any additional requirements are needed for State commission participation. Other commenters are concerned that State policy goals, such as California's Renewable Portfolio Standard, be included in the coordinated planning required by the Final Rule.[337] NARUC and California Commission also discuss State staff and fiscal constraints on participation, and California Commission suggests that the Commission consider a tariff rider to fund State participation.

Commission Determination

574. The Commission strongly encourages State participation in the transmission planning process and expects that all transmission providers will respect states' concerns, such as retail resource needs, in the planning

standards by the regional entitities (such as SERC) are adequate and appropriate.

[334] *E.g.*, American Transmission, Duke, and Progress Energy.

[335] Similar views are expressed by APPA, Arkansas Commission, Bonneville, California Commission, NCEMC, NYAPP, and CREPC. NYAPP, however, asks the Commission to be vigilant in not allowing State commissions improper control over the planning process.

[336] NYAPP, on the other hand, urges the Commission to require planning for all transmission facilities, not just bulk power facilities.

[337] *E.g.*, AWEA, California Commission, and Project for Sustainable FERC Energy Policy.

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 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 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.

d. Recovery of Planning Costs

583. In the NOPR, the Commission recognized that participants in the planning process must be assured of recovery of their costs incurred in the planning process, as well as assured that the costs will be borne equitably by all parties benefiting from the process. The Commission also sought comment on whether there should be a principle or requirement regarding cost recovery and allocation associated with funding the regional planning requirement.

Comments

584. Public utility commenters generally support the principle that costs should be borne by the beneficiaries of the process. EEI agrees, but argues that the Commission should not establish a specific cost basis for recovery, and several other commenters concur.[344] NorthWestern and PSEG support a cost causation principle for

[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.

[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.

[344] *E.g.*, Duke, Indianapolis Power, MidAmerican, Progress Energy, PSEG, South Carolina E&G, and SPP.

allocation of costs of planning, and Southern argues that entities that request any transmission sensitivity studies should bear the costs of those studies.

585. There is general agreement with the principle that costs should be recoverable, and some public utilities request that the Commission clarify that all planning costs not directly assigned are recoverable through transmission provider transmission rates.[345] Other commenters believe that the parties in the planning process should determine how planning costs should be allocated and funded. APPA urges simplicity, the avoidance of double collecting (*e.g.*, LSEs should not have to pay through both transmission rates and individually) and stresses the need to assess costs based on size and assets. Other comments are consistent with equitable allocation of planning costs.[346]

Commission Determination

586. We will not propose a specific method for recovery and allocation of planning costs in this Final Rule. We recognize, however, the importance of planning cost recovery and will require transmission planning processes to provide a mechanism for recovery of costs. We direct transmission providers to work with other participants in the planning process, as part of the collaborative process described above, to develop their cost recovery proposals in order to determine whether all relevant parties, including State agencies, have the ability to recover the costs of participating in the planning process. Transmission providers should also consider whether mechanisms for regional cost recovery may be appropriate, such as through agreements (formal or informal) to incur and allocate costs jointly. The Commission will consider resulting cost recovery proposals, including special riders to transmission rates, with an eye toward encouraging the broadest participation in the planning process possible.

e. Open Season for Joint Ownership

587. In the NOPR, the Commission expressed its belief that an open season to allow market participants to participate in joint ownership, particularly for large new transmission projects, could stimulate grid investment and ensure that all customers have the ability to participate in new projects on a nondiscriminatory basis. The Commission sought comment on whether to include such a requirement and, if so, what conditions or limitations should be associated with it.

Comments

588. As a general matter, a number of commenters believe that the planning process should include a mandate to construct identified upgrades or otherwise hold transmission providers accountable for carrying out the plan.[347] EEI and others argue that such a mandate would go beyond planning and result in providers giving up control of their systems. In their replies, LPPC and Sacramento assert that the decision to build facilities and to carry out transmission plans must rest with transmission providers and State authorities and that, in any event, it is unclear that the Commission has the authority to compel construction pursuant to regional transmission plans. At the October 12 Technical Conference, there was considerable discussion of the obligation to build and its relationship to the planning process proposed in the NOPR.

589. While not necessarily opposed to voluntary joint ownership arrangements in general, many commenters oppose the idea of mandated open seasons.[348] EEI provides a representative summary of the arguments of those opposed to open seasons. First, EEI argues that the Commission does not have the authority to order joint ownership and that joint ownership could interfere with State siting authority. It maintains that the instances where the Commission can order transmission construction are very limited and do not extend to the authority to order joint ownership.[349] Second, EEI argues that joint ownership will not provide the benefits cited by the Commission, stating that there is ample evidence that joint ownership of transmission lines is not needed to achieve economies of scale in construction. In its view, the level of transmission investment is currently increasing and joint ownership should not be expected to create additional sources of transmission investment. Third, EEI contends that prospective joint owners mistakenly believe they will not be subject to the same requirements as Commission-jurisdictional owners and urge the Commission to make clear that both jurisdictional and nonjurisdictional owners would be subject to the same requirements for service over jointly-owned facilities. If the Commission were to order joint ownership, Duke argues that it must condition such ownership by a nonjurisdictional entity on that entity filing a safe harbor OATT ensuring reciprocal open access by that joint owner.

590. Tacoma notes that ColumbiaGrid includes a mechanism for small users to participate in transmission projects in the proposal it is considering for its planning process. Xcel supports adopting the open season concept as an option in joint planning requirements. Though it does not completely oppose the principle, MidAmerican sees significant practical problems in developing and implementing an open season proposal and regards the open season idea as premature. Others generally support allowing for open seasons and joint ownership, but also do not believe they should be mandated.[350]

591. A number of other commenters, however, support requiring open seasons as a method of ensuring that identified upgrades are constructed. ELCON is strongly in favor, stating that open seasons for joint ownership is an ''idea whose time has come'' and expressing frustration that the Commission has not already acted on this proposal. FMPA argues that joint ownership will aid in providing additional capital for transmission projects. TDU Systems urge the Commission to require transmission providers, including RTOs and ISOs, to hold open seasons.[351] Joined by Arkansas Commission, TDU Systems argue that open seasons should not be limited to large projects. PGP supports open seasons when providers do not voluntarily agree to add capacity based on the results of the transmission plan. TDU Systems cite the Neptune and

[345] *E.g.*, Southern and South Carolina E&G.

[346] *E.g.*, Bonneville, NRECA, and CREPC.

[347] *E.g.*, APPA, East Texas Cooperatives Reply, FMPA, NCPA, TAPS, TDU Systems, Utah Municipals, and WIRES.

[348] *E.g.*, Allegheny, American Transmission, Constellation, New York Transmission Owners, MidAmerican, Duke, EEI, Entergy, FirstEnergy, MISO, National Grid, Northeast Utilities, NorthWestern, Progress Energy, PSEG, South Carolina E&G, SCE, Southern, SPP, Tacoma, Tucson, and Xcel.

[349] APPA, FMPA, TAPS, and TDU Systems, however, point to various sources of authority on which the Commission could rely to mandate open seasons and joint ownership, such as: To remedy undue discrimination under FPA sections 205 and 206; to carry out FPA section 214(b)(4)'s requirement to facilitate the planning and expansion of transmission facilities to satisfy the needs of load-serving entities; as a condition of market-based rate authority, FPA section 203 approval, or transmission rate incentives under FPA section 219; and under the permitting regulations promulgated under FPA section 216(c)(2)(B) dealing with backstop siting authority.

[350] *E.g.*, Bonneville, California Commission, and CREPC. Bonneville stresses that any jointly-owned facilities should have a single operator.

[351] Similar comments were made by APPA, Arkansas Commission, FMPA (includes a legal analysis in an attachment), NCPA, MISO/PJM States, Santa Clara, Southwestern Coop, TANC, and TAPS.

Cross-Sound Cable projects, where regulated utilities failed to provide solutions despite the need for expansion of the system in those regions. Seattle argues that voluntary joint ownership of projects should not be contingent upon an open season requirement. TANC points to current joint ownership arrangements in the Western Interconnection. Sacramento likewise notes that the joint planning and ownership process in the Western Interconnection has been a success, but asks the Commission to make clear that physical rights set asides are available in CAISO to accommodate non-LMP co-owners.

592. On reply, EEI, Entergy, and Southern repeat arguments against joint ownership and open seasons. EEI replies that FMPA's claim that joint ownership will result in increased investment is not based on fact and will not increase access. In its reply, TDU Systems states that joint ownership would not, as argued by EEI, infringe on State siting, as states would retain this authority over the jointly-developed project. APPA also stresses that its members have fewer difficulties obtaining service where joint ownership is permitted. In their replies, Lassen, Santa Clara, and TANC argue that the Commission should not, as suggested by Duke, condition the participation of a nonjurisdictional entity in a jointly-owned project on that entity filing a safe harbor OATT, as public power entities use the capacity they need and sell the rest whether or not they have a safe harbor OATT on file. However, TAPS asks on reply that access to jointly-owned facilities be available through a *pro forma* OATT. Participants at the October 12 Technical Conference expressed both support for joint ownership, as well as caution. National Grid states that it has had good success with joint ownership, but that jointly-owned projects are more complicated and can take longer to develop.

Commission Determination

593. The Commission believes there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers. The comments received in response to the NOPR support the notion that joint ownership can provide these benefits in many cases. For example, as TDU Systems note, the Neptune and Cross-Sound Cable projects have resulted in significant amounts of new transmission capacity in regions facing chronic constraints. We encourage joint ownership for other large backbone transmission upgrades included in the transmission plan developed by the planning process required by this Final Rule.[352]

594. We acknowledge, however, that joint ownership can increase the complexity of planning and developing a transmission project and are sensitive to concerns that formal open seasons can add to that complexity. We therefore do not mandate open season procedures to allow market participants to participate in joint ownership. We recognize that there may be reasons, given the complexity of the transmission grid and changing conditions of supply and demand for power, why any given facility identified in a transmission plan may not ultimately be constructed. Consequently, our planning reforms do not include an obligation to construct each facility identified in the plan, whether individually or through joint ownership mechanisms. At the same time, the Commission agrees that joint ownership may be useful in certain situations and encourages transmission providers and customers alike to consider the use of open seasons to realize construction of upgrades identified in the planning studies. If a transmission provider declines to construct an identified upgrade, we also encourage customers and third parties to consider, either individually or jointly, development and ownership of a project to the extent consistent with applicable State law.

f. Specific Study Processes Beyond Reliability and Congestion Reduction

595. In the NOPR, the Commission sought comment on whether there should be a specific study process to identify opportunities to enhance the grid for purposes beyond maintaining reliability or reducing current congestion. Such a study process could allow interested entities, including State resource agencies and others, to request the transmission provider to model grid upgrades needed to accommodate the construction of new resources and provide information needed to proactively evaluate such resources. The Commission expected that such studies would not conflict with State prerogatives, but rather would provide states with better information to evaluate all relevant resource options.

Comments

596. Most transmission provider commenters favor providing for study of some grid enhancement beyond reliability and congestion-related needs, but believe the Final Rule should not mandate a specific study process. Various commenters argue that the Commission should allow planning participants to determine details such as the scope, number, and cost responsibility for the studies.[353] MISO states that it is working on these issues, but enhancement beyond maintaining reliability or reducing congestion is a complicated subject best left to each RTO or ISO to decide.

597. Some commenters are more explicit or expansive in their recommendations. CAISO recommends that the Commission develop a policy to encourage construction of transmission lines necessary to connect renewable resources,[354] and Suez Energy NA provides similar comments about new remote generation. PJM believes the planning process should look at future congestion and building for resources not yet announced. The New Jersey Board believes that demand-side management and other solutions, such as distributed renewable generation, also should be considered. WIRES and ELCON believe all credible proposals should be studied. TAPS asserts that planning should study grid enhancements needed for new potential resources.[355] These views are consistent with the views of many of the commenters that support additional study processes.[356] TDU Systems, however, point out that planning for reliability and economics should be incorporated into the open and inclusive planning process and, therefore, a special study process should not be needed.

598. Other commenters are opposed to additional processes: South Carolina E&G does not see a need for additional studies; Southern believes additional study processes would be overly burdensome and would divert attention away from the fundamentals of prudent planning; and Bonneville notes that market participants often make requests

[352] As the Commission stated in Order No. 679–A, ''[t]he Commission will look favorably on incentive requests that include public power joint ownership.'' Order No. 679–A at P 102.

[353] *E.g.*, EEI, MISO, NorthWestern, PSEG, and Tacoma.

[354] Related to this, California Commission asserts that regional planning processes need to be closely linked with the resource adequacy planning processes and renewable energy portfolio standards on the State level.

[355] EEI replies in opposition to TAPS' assertions that planning should address transmission for potential resources, arguing that such a requirement would be cost prohibitive and would harm users.

[356] *E.g.*, APPA, Arkansas Commission, AWEA, CREPC, Sacramento, and Seattle.

for expensive studies without following through on them. Santee Cooper cautions the Commission against giving license to those who would attempt to hijack the regional planning process in order to advance a generation-related agenda, and notes that the Commission's authority does not extend to generation resource adequacy.

Commission Determination

599. We believe that development of a study process for identifying opportunities for grid enhancement beyond reliability and congestion reduction has the potential to provide useful information and would generally benefit development of the transmission grid. We therefore will include such study processes within the scope of Principle No. 8. In the NOPR, that principle concerned only congestion studies, but, as modified above, it now includes studies regarding upgrades that could integrate new generation resources. We note that various commenters argued for the consideration of demand resources in development of enhancements to the transmission grid.[357] As we explain above, consideration of such resources falls within Principle No. 8, as modified by the Final Rule.

g. Level of Detail in the OATT

600. In the NOPR, the Commission sought comment on the level of detail to be required to be in the transmission provider's OATT regarding its planning process.

Comments

601. Several commenters argued that the details of the planning process should be included in the transmission providers' OATTs.[358] Seattle noted that the OATT should balance the need for detailed planning requirements with the need for regional processes to evolve.

Commission Determination

602. The Commission agrees that the transmission planning attachment to a transmission provider's OATT must include sufficient detail to enable transmission customers to understand the transmission provider's planning process. This new attachment must therefore include:

(a) The process for consulting with customers and neighboring transmission providers;

(b) The notice procedures and anticipated frequency of meetings or planning-related communications;

(c) A written description of the methodology, criteria, and processes used to develop transmission plans;

(d) The method of disclosure of transmission plans and related studies and the criteria, assumptions and data underlying those plans and studies;

(e) The obligations of and methods for customers to submit data to the transmission provider;

(f) The dispute resolution process;

(g) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(h) the relevant cost allocation procedures or principles.

C. Transmission Pricing

1. General

603. As the Commission explained in Order No. 888, the *pro forma* OATT was designed to include primarily non-rate terms and conditions of open access non-discriminatory transmission service. Transmission providers first were required to adopt the non-rate terms and conditions of the *pro forma* OATT and then, in a subsequent filing under FPA section 205, to propose corresponding rates for service provided under their OATTs. Consistent with the focus of Order No. 888 on the non-rate terms and conditions of open access, the Commission did not propose broad reform of transmission pricing policy through the NOPR. Rather, the Commission identified in the NOPR several discrete pricing rules that it considered part and parcel of OATT service that merit reform, which we discuss in more detail later in this section. The Commission also specifically noted in the NOPR that the purpose of this rulemaking is to strengthen the *pro forma* OATT to remedy undue discrimination and not to create new market structures.

604. Despite the clear scope of this rulemaking, several commenters contend that broader ratemaking reforms should be implemented in order to remove obstacles to achieving competitive markets. Various commenters assert that rate pancaking must be eliminated in this reform, noting that the Commission has recognized in the past that pancaked rates inhibit the development of competitive markets.[359] Arkansas Municipal and TDU Systems contend that pancaked rates are particularly burdensome for customers with loads and resources on multiple transmission providers systems and those that sit essentially at or on the boundaries. TDU Systems argue that the failure to eliminate pancaked rates has caused many of the TDU Systems to spend many millions of dollars to build transmission from generation to interconnect with multiple control areas in order to avoid paying multiple wheeling charges.

605. Some of these commenters also advocate that the Commission should move towards joint rates.[360] Arkansas Municipal Power argues that moving toward joint rates outside an RTO will not only eliminate competitive barriers outside RTOs, but would reduce the disincentive to formation of new and expanded RTOs. TAPS complains that the NOPR requires regional planning, but has no provision requiring transmission providers to build facilities to support regional needs, arguing that joint rates would ease this problem. TDU Systems argue, however, that any joint rate methodology should not shift costs to other network customers, especially where surcharges are sought that might open the door to potential over-recovery by transmission providers as argued in the PJM/MISO proceedings. Old Dominion also contends that the Commission should add a requirement in the *pro forma* OATT that regional transmission costs be recovered through a single regional transmission rate of a rolled-in nature. Relative to cost recovery, Old Dominion believes that rolled-in zonal rates work for local facilities within a single transmission owner footprint, but regional rolled-in rates would be necessary for larger footprints.

606. Old Dominion also contends that the lack of periodic review by the Commission of stated transmission rates sends a strong economic signal to transmission owners to not invest in new transmission. Old Dominion argues that the Commission should require periodic rate reviews at least every five years or implement formula rates which would remove economic incentives for failing to build transmission.

607. EEI argues that the Commission should not address in this proceeding TDU Systems' proposal to require transmission providers to eliminate pancaked transmission rates in non-RTO regions because it involves complex issues that are not easily resolved. EEI contends that transmission providers should not be required to eliminate multiple transmission rates across multiple systems simply to allow TDU members to avoid the economic consequences of their decisions to

[357] *E.g.*, New Jersey Board, Ohio Power Siting Board, and WIRES.

[358] *E.g.*, APPA, NRECA, Old Dominion, and Seattle. APPA also suggests OASIS posting.

[359] *E.g.*, Arkansas Municipal, AWEA, FMPA, and TDU Systems.

[360] *E.g.*, Arkansas Municipal, TAPS, and TDU Systems.

purchase energy from off-system resources.

608. Other commenters ask the Commission to institute much broader market reforms in this rulemaking, arguing that the Commission will not be able to achieve its objectives of remedying undue discrimination and developing competitive wholesale markets without a fundamental change in market structures. Several commenters advocate changing the market structure in non-RTO markets to allow transmission customers to access the transmission provider's dispatch and redispatch options.[361] Some commenters [362] go further to assert that the Commission require the use of locational marginal pricing (LMP) as a part of OATT reform. Other commenters [363] assert that the Commission would not need to adopt a full RTO market design to achieve its more limited objectives, but contend that eliminating the fundamental inconsistency between the OATT rules and actual operation of the grid would remove a major obstacle to other reforms. Several commenters [364] contend that requiring use of a security constrained economic dispatch is a needed part of this reform.

609. Chandley-Hogan contend that the key element to ensuring transmission services are provided on a just, reasonable and not unduly discriminatory basis is to provide open access to the security constrained economic dispatch and the associated imbalance pricing that arises from that dispatch. Chandley-Hogan state that using a security constrained economic dispatch would also substantially reduce the problems inherent in the *pro forma* OATT's reliance on contract paths and ATC for transmission service scheduling.

610. Chandley-Hogan contend that a viable path to Order No. 888 reform is to start from the premise that open access to the dispatch (and redispatch) and marginal cost pricing for imbalances and redispatch to accommodate transmission are keys to getting open, non-discriminatory access to transmission. Chandley-Hogan argue that dispatch is the essential transmission service and providing open access to this dispatch is a path to achieving open, non-discriminatory access to transmission. Chandley-Hogan contend that a third party cannot effectively access the grid without accessing and closely interacting with the system operator's dispatch, including determining if transmission service is available, acquiring redispatch service to allow its schedule to proceed without curtailment, and settling imbalances from scheduled levels. Williams agrees with Chandley-Hogan that a system allowing non-RTO utilities to deny and curtail service requests whenever there is little ATC left and without offering redispatch to a third party is completely flawed. Williams argues that these same requests would be accommodated in an RTO through redispatch as long as the RTO has sufficient offers to arrange a security constrained economic dispatch.

611. EPSA argues on reply that an all-inclusive, ''asset-blind'' administration of open dispatch is needed to fully eliminate undue discrimination. EPSA states that security constrained dispatch will provide reliable operation and efficient utilization of the transmission grid by promoting the use of newer, cleaner and less expensive power plants. EPSA urges that these issues should be explored further here or in another policy proceeding. Project for Sustainable FERC Energy Policy asserts that there is no assurance of non-discriminatory access to transmission services and competitive wholesale markets unless load and potential competitors of the control area operators are treated comparably during dispatch. Project for Sustainable FERC Energy Policy supports additional provisions to the *pro forma* OATT requiring transparency and fairness in system dispatch and redispatch such as either an ''open dispatch'' requirement or a rule-based framework with standards of conduct and OASIS disclosure, as well as reporting and auditing requirement to eliminate anticompetitive incentives. Project for Sustainable FERC Energy Policy argues that sufficient data to establish marginal system costs and permit comparisons with the prices/costs of neighboring systems should be disclosed on OASIS.

612. PJM proposes open dispatch consisting of control of the dispatch function by a disinterested entity and the institution of a spot or balancing market to allow for the formation of real-time prices. Project for Sustainable FERC Energy Policy encourages the further separation of the system operator's dispatch functions from its merchant functions, to include specific dispatch transparency and comparability mandates as per PJM's and Transparent Dispatch Advocates' request. Project for Sustainable FERC Energy Policy supports comparable dispatch services through an independent entity. In its reply comments, Williams supports the rules based dispatch service proposed by PJM and states that it will reduce the opportunity for transmission providers to levy unjust and unreasonable redispatch rates.

613. PJM also contends that non-RTO/ISO systems have negative impacts on RTO systems because of the respective treatment of import transactions by non-RTOs/ISOs and RTOs/ISOs and the incidence of loop flows in market environments. PJM argues that entities scheduling flows through PJM that actually loop onto other systems nevertheless benefit financially because they collect the difference between the relatively high price at the interface where the energy is scheduled to enter the PJM footprint and the lower price at the interface where the energy is scheduled to leave the PJM footprint. When energy does not flow as scheduled, PJM states that the otherwise expected, beneficial impact on the transmission constraints are not realized, resulting in price differentials between the affected interfaces. As a result, PJM contends that such scheduled transactions only contribute to the FTR revenue adequacy issues PJM has experienced over the last 12 months.

614. PJM asserts that it is unduly preferential for a non-RTO/ISO utility to take advantage of the benefits of the organized markets of a bordering RTO/ISO without any obligation to bear any of the costs of administering those markets. PJM contends that it is unduly discriminatory and an impediment to the development of competitive markets to permit a non-RTO/ISO utility adjacent to an RTO/ISO's organized, transparent markets to accept the benefits of those markets and the regional transmission planning process that sustains them, while the same utility relies on non-market-based congestion management and limits the access of its competitors, including those who are members of the relevant RTO/ISO, to its dispatch sequence and wholesale prices within its service area. PJM asks the Commission to declare that it would not be unduly discriminatory for an RTO/ISO to include in its tariff a provision that makes an external system operator's access to those markets contingent on the external operator providing reciprocal access to its dispatch and planning functions for RTO/ISO members, as well as access to the external system's real-time marginal system cost information.

615. Transparent Dispatch Advocates propose on reply that the Commission require the industry to develop inter-

[361] *E.g.*, Chandley-Hogan, Constellation, and PJM.

[362] *E.g.*, Morgan Stanley and Steel Manufacturers Associations.

[363] *E.g.*, Chandley-Hogan and PJM.

[364] *E.g.*, EPSA and Chandley-Hogan.

control area coordination agreements to provide for reciprocal redispatch to alleviate constraints at specified border flowgates. Transparent Dispatch Advocates argue that redispatch over a larger area provides transmission providers more options to extract the full efficiency of their systems by allowing import/export transactions and intra-control area flows to continue that would otherwise be curtailed by providing redispatch of generation across a border at a lower cost than would result had the transaction been curtailed. Transparent Dispatch Advocates further propose that the Commission establish principles in the Final Rule to guide the development of these coordination agreements and require filing of the agreements within 12 months of the issuance of the Final Rule. Transparent Dispatch Advocates suggest that technical conferences may need to be scheduled to address any utility specific issues that arise.

616. Morgan Stanley and Steel Manufacturers Association contend that every control area should be moving toward LMP and that facing an imbalance cost measured by full replacement value of redispatch measured under LMP is the correct incentive to follow a schedule. Entegra similarly argues that customers and State regulators would benefit from more transparency regarding congestion on the transmission system and that the most efficient way to provide this transparency is to require transmission providers to apply LMP models to their systems and to post the resulting modeled LMPs.

617. Several commenters object to the proposal for a mandatory all-inclusive redispatch using bid-based pricing.[365] These commenters generally argue that such a proposal could not lawfully be adopted in the Final Rule because it dramatically departs from the scope of the NOPR. They also argue that the proposal is bad policy because there is no record showing that consumers would benefit from the costly and disruptive implementation required for the proposal and that adoption of the proposal would create controversy given that Congress and the Commission have already rejected an LMP-based model of industry restructuring. Sacramento adds that given the record of transmission investment in RTOs, open redispatch might not meet the transmission expansion goals of the NOPR.

618. Southern argues on reply that there is no legal basis for claims that a lack of open dispatch results in undue discrimination. Southern states that the entities at issue are not similarly situated and that open dispatch concerns resource procurement, an area beyond the scope of the Commission's jurisdiction. Southern further argues that the open dispatch remedy proposed by PJM and others would require radical restructuring and market reforms that are unfounded, lack a legal basis and would result in political discord. Southern states that open dispatch would violate FPA section 217 by threatening the ability of LSEs to maintain access to transmission rights to serve native load. In its reply comments, Entergy states that the open dispatch proposal should be rejected because it is unnecessary to ensure open access transmission service, is contrary to the Congressional intent in passing EPAct 2005, exceeds the scope of the Commission's jurisdiction by overriding State jurisdiction over sales to retail customers, and would result in opposition that will delay other reforms and distract the Commission with divisive litigation.

619. Sacramento states that the proposals for mandatory redispatch, the control of the dispatch by a disinterested entity, and the institution of a spot or balancing market to allow for the formation of real-time prices would undermine customers' objectives to receive uninterrupted transmission service at a predictable price and ignore transmission system operational limitations. Sacramento states that the value of mandatory redispatch in the Western Grid is limited because constraints often overlap and change from thermal to voltage to stability constraints at differing load levels and redispatching large amounts of generation to relieve constraints because of the distance between loads and generation cannot be achieved in the timeframes required to maintain reliability. Sacramento is concerned that PJM's proposal would cause appropriation of generation built to serve a transmission provider's native load in order to effectuate third-party transmission transactions, strain the transmission provider's grid, and cause additional curtailment of native load and firm transactions when a force majeure event occurs.

620. Entergy cites the approval of the ICT proposal as ample evidence that the incremental approach proposed in the NOPR is a better means of improving clarity, transparency and improvements in dispatch efficiency than the Transparent Dispatch Advocates and PJM seek to mandate. Entergy states that the arguments posed by PJM and Chandley-Hogan do not target remedying discrimination or ensuring comparability, but rather focus on what they believe are mechanisms for more efficient use of the grid. Overall, Entergy does not support any changes to the basic nature of the services available under the *pro forma* OATT or the development of real-time markets to ensure comparable access.

621. In its reply comments, Sacramento disagrees with PJM's claims that TLRs are a discriminatory substitute for real-time redispatch and PJM's proposal to eliminate such use of TLRs in favor of an expanded redispatch obligation. Sacramento argues that firm customers under the *pro forma* OATT do not expect TLRs, while those in Day 2 RTOs expect that generation will be redispatched. Sacramento adds that TLRs affect all loads, but that the nature of firm physical rights service is that it will not be interrupted except in very narrow defined circumstances.

622. Southern argues that customers selling between RTO and non-RTO systems are treated equally since part of the transaction is under an LMP treatment and the other part is under OATT treatment. In response to PJM's allegations that loop flows are unduly discriminatory to its customers, Southern states that loop flows are unavoidable consequences of integrating electrical systems and that PJM itself imposes loop flows on non-RTO systems, the effects of which are not compensated by PJM. If PJM believes that entities are free-riding on its system or manipulating its system, Southern argues that PJM could seek to increase market participation charges or file a complaint with the Commission. Sacramento agrees that this rulemaking is the wrong forum for resolving seams issues given the stated scope of the NOPR. Sacramento adds that border utilities do not ''free ride'' on RTO markets because these markets impose significant costs on border entities. Sacramento also disagrees that open redispatch would resolve loop flow problems and suggests other mechanism for addressing loop flow. Finally, Sacramento states that TLRs are an Eastern Interconnection process that, although rare, occur in RTOs and non-RTO areas.

Commission Determination

623. As the Commission explained in the NOPR, we do not intend to undertake a comprehensive overhaul of our transmission pricing policies in this rulemaking. Instead, the Commission proposed a number of specific reforms to discrete provisions in the *pro forma* OATT and a clarification to our ''higher of'' policy for pricing of transmission system expansions. Given the limited

[365] *E.g.,* LPPC, Entergy, and Sacramento.

scope of this proceeding, we do not believe it would be appropriate to adopt the broader ratemaking proposals suggested by commenters. Issues of rate pancaking, including joint rates, regional rolled-in rates and rate reviews are beyond the scope of this proceeding.

624. Similarly, the Commission made clear in the NOPR that the purpose of the proposed rule is to strengthen the *pro forma* OATT to remedy undue discrimination and not to impose any particular market structure on the industry. The Commission's focus in this proceeding was and remains the development of competitive wholesale markets through the reduction of barriers to entry created through the control of transmission assets. We continue to believe that the appropriate focus of this rulemaking is to strengthen competitive wholesale markets by adopting reforms to address remaining areas of undue discrimination and issues of comparability rather than mandating a fundamental change in the market structure.

625. We therefore reject requests to institute systems that require the real-time use of regional security constrained economic dispatch and LMP for granting real-time transmission service and for the settlement of imbalances or to otherwise require transmission providers to use LMP-based modeling. We believe that LMP market designs can provide significant benefits to customers through more efficient use of the grid, but do not believe that such market designs are the only way to remedy undue discrimination or achieve comparability. We continue to support regional flexibility in market development, provided that the market design implemented by the transmission providers provides other transmission customers with comparable service to that which the transmission providers provide to their own native loads and affiliates.

626. We also reject arguments regarding seams issues creating an undue discrimination between market and non-market areas that must be resolved in this proceeding. We note that there are currently processes underway to address seams issues both in the Eastern and Western Interconnections.[366] We believe that such seams issues are beyond the scope of this rule and are better addressed on a case-by-case basis or, as appropriate, in the proceeding on RTO Border Utility Issues.[367]

2. Energy and Generation Imbalances

627. In Order No. 888, the Commission concluded that six ancillary services must be included in an OATT.[368] One of those ancillary services is energy imbalance service under Schedule 4 of the pro forma OATT.[369] Energy imbalance service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area.[370] The Commission recognized, in general, that the amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer.[371]

628. The Commission found that energy imbalance service should have an energy deviation band appropriate for load variations and a price for exceeding the deviation band that is appropriate for excessive load variations.[372] The Commission established an hourly deviation band of +/−1.5 percent (with a minimum of 2 MW) for energy imbalance. The Commission explained that this deviation band promotes good scheduling practices by transmission customers, which ensures that the implementation of one scheduled transaction does not overly burden another.[373]

629. With respect to compensation associated with the hourly energy deviation band, the Commission explained that, for energy imbalances within the deviation band, the transmission customer may make up the difference within 30 days (or other reasonable period generally accepted in the region) by adjusting its energy deliveries to eliminate the imbalance (*i.e.*, return energy in kind within 30 days).[374] In addition, the Commission explained that the transmission customer must compensate the transmission provider for each imbalance that exceeds the hourly deviation band and for accumulated minor imbalances that are not made-up within 30 days.[375] With respect to the price of energy imbalance service, the Commission explained that it intentionally did not provide detailed pricing requirements.[376] Instead, the Commission required transmission providers to propose rates for energy imbalance service.[377]

630. Although transmission providers have different energy imbalance charges, they typically require customers to correct energy imbalances within the deviation band through return in kind or a financial settlement that requires payment for underdeliveries of energy equal to 100 percent of the transmission provider's system incremental cost for the hour the deviation occurred. For energy overdeliveries, the transmission customer would receive a payment equal to 100 percent of the transmission provider's decremental cost for the hour the deviation occurred.[378] Outside the deviation band, transmission providers either charge the transmission customer (1) A percentage of the utility's system cost, such as 110 percent of incremental costs for underscheduling or 90 percent of decremental costs for overscheduling or (2) the greater of a percentage of system costs or a fixed charge, such as $100 per MWh.[379]

631. While the Commission found in Order No. 888 that energy imbalance was an ancillary service, it also recognized that another imbalance may arise for differences between energy scheduled for delivery from a generator and the amount of energy actually generated in an hour,[380] commonly called generator imbalance. The Commission concluded, however, that a generator should be able to deliver its scheduled hourly energy with precision and expressed concern that allowing a generator to deviate from its schedule by 1.5 percent without penalty, so long as

[366] See, *e.g.*, *RTO Border Utility Issues*, Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnections, (Docket No. AD06–9–000) (issued Jan. 25, 2007).

[367] *Id.*

[368] Order No. 888 at 31,703.

[369] *Id.*

[370] *See Id.* at 31,960.

[371] Order No. 888–A at 30,230.

[372] *Id.*

[373] *Id.* at 30,232.

[374] *Id.* at 30,229.

[375] *Id.* The Commission further stated that the *pro forma* OATT permits schedule changes up to twenty minutes before the hour at no charge, and that it would allow the transmission provider and the customer to negotiate and file another deviation band more flexible to the customer, if the same deviation band is made available on a not unduly discriminatory basis. *Id.* at 30,232–33.

[376] *Id.* at 30,234

[377] *Id.*

[378] *See, e.g.,* Arizona Public Service Co., FERC Electric Tariff, Twelfth Revised Volume No. 2, Schedule 4 (Energy Imbalance Charge), accepted in *Arizona Public Service Co.,* Docket No. ER04–442–003 (Sep. 30, 2004) (unpublished letter order); Public Service Company of New Mexico, FERC Electric Tariff, Second Revised Volume No. 4., Schedule 4 (Energy Imbalance Charge), accepted in *Public Service Co. of New Mexico,* Docket No. ER04–416–002 (Sep. 30, 2004) (unpublished letter order).

[379] *See Idaho Power Co.,* 102 FERC ¶ 61,351 (2003); Duke Electric Transmission FERC Electric Tariff, Third Revised Volume 4, Original Sheet No. 120 accepted in *Duke Energy Corp.,* Docket No. ER04–812–001 (Jul. 2, 2004) (unpublished letter order).

[380] Order No. 888–A at 30,230.

it returned the energy in kind at another time, would discourage good generator operating practices.[381] The Commission stated that a generator's interconnection agreement with its transmission provider or control area operator should specify the requirements for the generator to meet its schedule and any consequence for persistent failure to meet its schedule.[382]

632. The Commission subsequently accepted in a number of cases modifications to a transmission provider's OATT to include generator imbalance provisions.[383] Moreover, in Order No. 2003–B, the Commission permitted the transmission provider to include a provision for generator balancing service arrangements in individual interconnection agreements.[384] Further, in a NOPR concerning generator imbalance provisions for intermittent resources, the Commission proposed to establish a standardized schedule under the *pro forma* OATT to address generator imbalances created by intermittent resources and to clarify the application of the current energy imbalance provision of the *pro forma* OATT.[385] In particular, the Commission proposed that generator imbalance provisions for intermittent resources would reflect a deviation band of +/−10 percent (with a minimum of 2 MW) and allow net hourly intermittent generator imbalances within the deviation band to be settled at the system incremental cost at the time of the imbalance.[386] The Commission also reiterated its policy that a transmission provider may only charge the transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.[387]

633. A variety of different deviation bands and pricing methods are on file for generator imbalances. Rates for generator imbalance underdeliveries range from the greater of $100/MWh or 110 percent of system incremental cost to the greater of $150/MWh or 200 percent of the incremental cost.[388] Generator imbalance rates for overdeliveries range from 90 percent[389] of system decremental cost to 50 percent[390] of the decremental cost.

a. Tiered Approach to Imbalance Penalties in the OATT

NOPR Proposal

634. In the NOPR, the Commission noted that the existing energy imbalance charges described in Order No. 2003 are the subject of significant concern and confusion in the industry. The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provides the proper incentive to keep schedules accurate without being excessive. The Commission therefore proposed to modify the current *pro forma* OATT Schedule 4 treatment of energy imbalances and to adopt a separate *pro forma* OATT schedule for the treatment of generator imbalances.

635. The Commission proposed to create new energy and generator imbalance schedules based on the following three principles: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

636. The Commission noted that Bonneville has adopted an energy imbalance pricing approach based on a three-tiered deviation band that appears workable for both energy imbalance service and generation imbalance service. Under this approach, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) would be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) would be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) would be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances. Intermittent resources are exempt from the third-tier deviation band and pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts.

637. The Commission sought comment regarding whether this tiered approach should be adopted for inclusion in the *pro forma* OATT for energy and generator imbalances. The Commission specifically asked whether this approach provides sufficient incentives to ensure that transmission systems can be operated in a reliable manner and ensure that customers are treated in a just and reasonable manner.

Comments

638. A number of entities generally support a tiered approach to imbalance penalties that progressively increases the penalties for imbalances, as implemented by Bonneville.[391] These

[381] *Id.*

[382] *Id.*

[383] *See, e.g., Niagara Mohawk Power Corp.,* 86 FERC ¶ 61,009, *order on reh'g,* 87 FERC ¶ 61,148 (1999) (*Niagara Mohawk*); *PacifiCorp,* 95 FERC ¶ 61,145, *order on reh'g and clarification,* 95 FERC ¶ 61,467 (2001); *Alliant Energy Corporate Services, Inc.,* 93 FERC ¶ 61,340 (2000); *Wolverine Power Supply Coop.,* 93 FERC ¶ 61,330 (2000); *Commonwealth Edison Co.,* 93 FERC ¶ 61,021 (2000); *FirstEnergy Operating Cos.,* 93 FERC ¶ 61,200 (2000), *order denying reh'g & granting clarification,* 94 FERC ¶ 61,184 (2001); *Tampa Electric Co.,* 90 FERC ¶ 61,330 (2000), *reh'g denied,* 95 FERC ¶ 61,101 (2001); *Florida Power Corp.,* 89 FERC ¶ 61,263 (1999); *Consumers Energy Co.,* 87 FERC ¶ 61,170 (1999) (*Consumers*).

[384] Order No. 2003–B at P 74–75.

[385] *Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets,* Notice of Proposed Rulemaking, 70 FR 21349 (Apr. 26, 2005), FERC Stats. & Regs. ¶ 32,581 at P 9 (2005) (Imbalance Provisions Proceeding).

[386] The Commission defined incremental cost as ''the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs and taxes.'' *Id.* at P 9 n.17 (*citing Consumers,* 87 FERC ¶ 61,170 at 61,179 (1999)).

[387] Under existing Commission policy, a transmission provider may only charge a transmission customer for the penalty percent adder to the incremental cost for either hourly generator imbalances or hourly energy imbalances for the same imbalance. For example, if a transmission customer has a 100 MWh point-to-point schedule in a control area, but produces 105 MWh and consumes 105 MWh, the transmission provider may charge the transmission customer 110% of its incremental cost for the 5 MWh of energy imbalance, but then must pay the transmission customer its incremental cost for the 5 MWh generator imbalance.

[388] *See Duke Energy Corp.,* Docket No. ER05–855–000 (Dec. 20, 2005) (unpublished letter order) (accepting Duke Electric Transmission's Large Generator Interconnection Agreement with Power Ventures Group, LLC (Duke Delegated Letter Order)).

[389] *See Entergy Services, Inc.,* 90 FERC ¶ 61,272 (2000) (concerning various generator imbalance agreements).

[390] *See* Duke Delegated Letter Order.

[391] *E.g.,* Ameren, Northwest IOUs, Progress Energy, Suez Energy NA, Public Power Council, Sacramento, South Carolina E&G, Pinnacle, Allegheny, TDU Systems, Constellation, Imperial, and Morgan Stanley.

commenters generally state that a graduated bandwidth approach recognizes the link between escalating deviations and potential reliability impacts on the system. Other entities, however, take issue with aspects of the Commission's proposal or propose a different approach to resolving imbalances. For example, Entegra submits that the Commission should require transmission providers to establish, or permit market participants to establish, markets or pools for the netting and settlement of imbalances. Steel Manufacturers Association argues for the Commission to require real-time balancing markets.

639. Among those supporting the Commission's proposal, Ameren asserts that the tiered approach properly allows for higher penalties for imbalances that have a greater impact on the system and thus have a greater potential to affect reliability. NorthWestern is not opposed to the generation imbalance provisions applying to all generators, arguing that imbalance charges must be based upon incremental cost and must provide an incentive for accurate scheduling. Morgan Stanley contends that basing the imbalance charge on incremental cost should be a bedrock principle for developing methods to financially settle imbalances.

640. Progress Energy, Sacramento, and Entergy encourage the Commission to allow each transmission provider to have the flexibility to craft penalty provisions that provide the right incentives to encourage their transmission customers to act responsibly. Grant similarly contends that the transmission provider must be able to decide what to charge for imbalance services and must consider the incentives for resource development and the potential for cross-subsidies paid by other customers associated with such pricing. Grant argues that transmission providers should have an ability to ''opt out'' if they can demonstrate an inability to provide the service without creating an undue burden on other ratepayers.

641. Constellation, while supporting the Commission's proposal, asks that transmission providers be required to utilize a security-constrained economic dispatch to procure and settle imbalances at least cost, which would ensure that least cost is determined on the most efficient basis. Constellation contends that imbalance charges should be based on the transmission provider's actual cost of meeting a positive imbalance or liquidating a negative imbalance, which costs can include required ancillary services and redispatch costs. Morgan Stanley states that facing an imbalance cost measured by full replacement value of redispatch measured under LMP would be an appropriate incentive. Morgan Stanley contends that the *pro forma* OATT should specify using opportunity cost principles to charge for imbalance solutions in those areas without LMP and come as close to mimicking the result under LMP as possible. In reply comments, Mark Lively suggests the Commission make the price for imbalances a function of the size of Area Control Error. Public Power Council recommends that transmission providers not assess penalties against loads or resources when their deviations from the schedule help the system in a given delivery hour. TDU Systems argue that inadvertent scheduling errors that do not threaten system integrity or reliability should not be penalized through charges for imbalances that exceed incremental cost in the upper tiers of imbalance bandwidths.

642. Although FirstEnergy states that the Bonneville approach for generator imbalances is appropriate, it argues that the current *pro forma* OATT methodology for calculating and assessing energy imbalances should be retained. FirstEnergy argues that it is more appropriate and fair to apply a graduated penalty structure to generation imbalances since greater deviations usually occur from generation. Ameren, however, believes that generators are generally better able to control their imbalances than transmission customers who take energy off of the system and that the use of a narrower deviation band may be appropriate for generator imbalances. Nonetheless, Ameren states that it does not oppose the Commission's proposal to use the same deviation bandwidths for both energy imbalances and generator imbalances.

643. Ameren contends that developing standardized provisions for generator imbalances in the OATT would eliminate the plethora of penalties that now exist. Ameren asserts that moving to a tariff approach would increase transparency and would help address the situation where such provisions may appear either in the relevant OATT or in specific interconnection agreements (at least for interconnection agreements entered into as of the date of the revised tariff provisions). Progress Energy and South Carolina E&G support separate tariff (or Generator Interconnection Agreement) provisions for these services, suggesting that generator and energy imbalance provisions could be tailored for generators and LSEs. NorthWestern states that it has long been an advocate of the inclusion of a generation imbalance OATT mechanism. TDU Systems contend that the Commission should require that the specific bandwidths and the basis for the charges be spelled out in detail in the revisions to the *pro forma* OATT and in each transmission provider's tariff. Allegheny argues that changing Energy Imbalance Service from Schedule 4 to Schedule 4a, adding a new Schedule 4b for Generator Imbalance Service, and eliminating proposed Schedule 9 would call attention to the fact that a transmission provider may only charge a transmission customer either an hourly generator imbalance charge or an hourly energy imbalance charge, but not both for the same imbalance.

644. Other entities contend that the Commission's imbalance proposal will not do enough to protect reliability and prevent entities from deviating from their schedules. Entergy states that the Commission should recognize that a system with significant hydro resources, such as the Bonneville system, faces different challenges in matching generation and load than a system with predominantly thermal generation. Unlike the fast ramping capability of hydro units, Entergy asserts that thermal units have a more limited ability to adjust and compensate for imbalances. Entergy adds that the Bonneville model may not provide sufficient incentives in those areas with large amounts of independent generation. In reply comments, some APPA members noted that wind variability may pose significant operational concerns that could increase regulating reserve requirements, particularly on smaller transmission systems.

645. Steel Manufacturers Association asks the Commission to delete any further reference to charges based on some multiple of incremental costs, which applies to scheduling incentives, not cost recovery. It believes that charges based on multiples of incremental costs are not necessary and do not produce rates that are just and reasonable. Steel Manufacturers Association asserts that balancing mechanisms based on real time market-clearing prices provide full compensation and adequate scheduling incentives in the organized markets and there is no reason to apply a deadband/penalty mechanism for individual OATT providers unless there is a demonstrated need, *i.e.*, a showing that excessive gaming by LSEs or generators has been a problem.

646. Steel Manufacturers Association also contends that the current imbalance mechanism is a losing proposition for loads that cannot control energy

consumption to match an hourly schedule of energy deliveries, with transmission providers receiving windfall revenues. It argues that the mechanism is unfair to smaller transmission systems that are not control areas (and therefore may not settle all of their imbalances through return-in-kind energy) and certain retail customers that take unbundled retail transmission service. Steel Manufacturers Association asks the Commission to institute a larger bandwidth of, at minimum, 10 percent for small wholesale customers and discrete retail loads. It contends that large utilities and wholesale transmission customers that acquire power for many discretely operated loads with varying load stages and load factors and averaging those loads creates an overall predictability to load curves that permits the practical use of a 1.5 percent bandwidth for large utilities and wholesale customers.

647. Utah Municipals assert that the Commission is wrong to believe that imbalances tend to result from carelessness or intentional conduct rather than unavoidable uncertainties and error. Utah Municipals contend that, while technology that permits perfectly accurate scheduling (*i.e.*, namely the AGC equipment used by control area operators) is theoretically available, it is prohibitively expensive for many transmission customers and unavailable to those who do not own generation. Utah Municipals argue that financial incentives for accurate scheduling do not alter scheduling behavior or actual imbalances, but only result in a potential windfall for the transmission provider and a potentially significant competitive advantage for the transmission provider's market function, which (because of the AGC equipment that all transmission customers pay for through rates) will not be subject to the charges. Utah Municipals suggest that the Commission limit the imbalance charges for unintentional deviations by applying the third deviation band only to intentional imbalances.

648. Imperial argues that the Bonneville approach would not provide appropriate incentives for small geothermal generating units on its system to control their scheduled output, especially if imbalances are recorded on an hourly basis rather than on a cumulative basis over the course of a month. Under the Bonneville approach, Imperial asserts that it would have to pay its generators 100 percent of its incremental cost for overgeneration because such imbalances are usually less than 2 MW in any given hour. It states that using a 100 percent credit for net overgeneration would result in crediting the generator more than $28,500.

649. WECC states that it is very important to differentiate between the kind of behavior that the Commission is worried about and appropriate practices that support system reliability. WECC is concerned that inflexible generator imbalance provisions in the *pro forma* OATT may create incentives for generators in the West to restrict governor action on their generators in ways that degrade system reliability. WECC notes that the number of rotating machines connected to the grid in the Eastern Interconnection is much greater than in the Western Interconnection, which impacts the ability of generators to respond to maintain frequency when a system's load-resource balance changes. WECC explains that a sudden change in load-resource balance of a particular magnitude (for example, the loss of a 1,000 MW generating plant) will require a proportionately greater response from each generating unit in the West as compared to the Eastern Interconnection. WECC contends that in the West a significant frequency decline could cause responding generators to exceed a 1.5 percent deviation threshold applied under current *pro forma* Tariff imbalance schedules.

650. If the manner of implementing generator imbalance charges in the West does not consider the need for generators to respond to frequency deviations, WECC worries that these charges could produce perverse incentives that will undermine reliability. WECC argues that generators that use set-point controllers to override governor action will be less likely to incur imbalance charges and penalties, while those with properly operating governors may be punished for deviating from scheduled output to respond to system reliability needs. WECC believes that this has in fact been happening in the West and is one of the reasons that frequency response in the Western Interconnection has deteriorated in recent years. WECC urges the Commission to consider how generators can be given appropriate incentives to meet their obligations to supply energy to load but also to support system reliability by effectively responding to frequency deviations. WECC explains that the Commission could adopt a policy that set-point controllers should not be allowed to override governor response. WECC suggests that deviations from scheduled generator output needed to correct frequency decay could be excused from imbalance penalties under the *pro forma* OATT.

651. Indianapolis Power contends on reply that variation should be allowed to account for the individual facts and circumstances associated with a specific region as well as specific types of intermittent resources. A number of entities agree with providing flexibility to intermittent generators, but suggest different ways of doing so.[392] Fertilizer Institute agrees that intermittent resources should be exempt from any penalties beyond the 90 percent/110 percent ''second tier.'' However, Fertilizer Institute also believes that intermittent resources should receive greater tolerance before they run into the 90 percent/110 percent penalty level in the first place. Fertilizer Institute urges the Commission to relax the first-tier tolerance band from 2MW to 20MW (or 40 percent of nameplate capacity, whichever is greater) for intermittent generators only. It asserts that this action is consistent with the Commission's recognition that intermittent generators can undergo sudden changes of conditions for which they cannot fairly be held responsible. Fertilizer Institute argues that a broader first-tier tolerance band for these generators will present no threat to the transmission grid, because intermittent generation facilities are limited both in size and in number.

652. Geothermal Producers supports a first-tier deviation band of +/−5 percent for intermittent resources, rather than the 1.5 percent threshold proposed by Bonneville. Geothermal Producers believes a 5 percent band is appropriate for intermittent resources, since a five percent band more accurately recognizes that intermittent resources are less capable of controlling deviations from schedules than are conventional resources. For over- or under-deliveries in excess of five percent, Geothermal Producers contends that intermittent resources should be charged no more than the control area's cost of supplying energy to correct the imbalance. Geothermal Producers also supports Bonneville's position that intermittent resources should be exempt from the third-tier deviation band and instead should pay the second-tier deviation band charges for all deviations greater than the second-tier deviation band.

653. Other commenters, however, do not support providing exceptions for

[392] *E.g.*, NorthWestern, Fertilizer Institute, and Geothermal Producers.

intermittent resources.[393] If society decides to provide incentives for intermittent resources, Morgan Stanley states that this is better done in a direct fashion, such as a certification program akin to resource adequacy rules that require LSEs to source a proportion of supply from such resources. Morgan Stanley asserts that this would motivate developers to mitigate imbalance costs through other market or technical means to the full extent of the economic signal imbedded in the imbalance price and thereby optimize the design and operation of such resources. MidAmerican argues on reply that special treatment of intermittent resources and loads has the effect of penalizing those resources and loads that have made investments to manage scheduling and enhance reliability. TDU Systems believe that the NOPR's third principle, which requires transmission providers to accord special treatment to intermittent generators, is contrary to the principle of comparability.

654. Northwest IOUs argue that the transmission provider should have the option to elect whether to exempt intermittent resources from the third-tier deviation band and instead charge, in a not unduly discriminatory or preferential manner, the second-tier deviation band charge for all deviations greater than the larger of 1.5 percent or 2 megawatts.

655. Several commenters suggested that the Commission include a definition of intermittent resource in the final rule. Fertilizer Institute and South Carolina E&G contend that it is essential for the Commission to provide a clear definition of ''intermittent generation'' or ''intermittent resource'' to avoid disputes. Fertilizer Institute argues that the question of whether a given generator is ''intermittent''—and thereby entitled to the special provisions—is likely to become a source of contention. Fertilizer Institute suggests that an intermittent resource be defined as ''an electric generator that (1) Cannot store its fuel sources and (2) has limited capability to be dispatched and to respond to changes in system demand and transmission security constraints.'' EEI, however, suggests that the definition apply only to weather-driven units. Fertilizer Institute argues on reply that restricting the definition in this way would be unduly discriminatory. Fertilizer Institute argues that the definition should include the most common forms of intermittent generation—wind and solar power—as well as the less common but equally valuable forms, such as generation with ocean energy or ''waste heat'' from an industrial process. Fertilizer Institute asserts that the Commission should not broaden the definition of intermittent resource to encompass generators who are not truly ''intermittent'' and should not narrow the definition to exclude some intermittent generators in favor of others. Fertilizer Institute contends on reply that a generator should not have to be ''weather-driven'' to qualify as ''intermittent.'' Geothermal Producers supports the inclusion of geothermal energy as an intermittent resource. Geothermal Resources contends that geothermal resources satisfy both the Commission's proposed definition and the EEI proposal.

656. Ameren and Entergy ask the Commission to clarify that it does not intend to amend any existing interconnection agreements to require the use of any *pro forma* imbalance penalties. Entergy believes that the present form of its Generation Interconnection Agreement is absolutely critical to managing imbalances on its system and maintaining reliability. Entergy states that it has developed specialized software to monitor and manage generator imbalances and employs six system operators (one per shift) to monitor and manage generator imbalances.

657. Although Entergy supports the ''grandfathering'' of existing generator imbalance arrangements, it does not believe that it would be appropriate to require the prospective use of a different methodology while simultaneously maintaining the grandfathered arrangements. Entergy contends that administering two different generator imbalance arrangements would not be consistent with the comparability principles of Order No. 888 and would be difficult and costly from an operational perspective.

658. Several commenters[394] argue on reply that it would be inappropriate for the Commission to grandfather existing imbalance provisions. In its reply comments, Entegra argues that prior arrangements should remain in place only if a transmission provider can demonstrate that its existing imbalance arrangements are consistent with or superior to the provisions of the *pro forma* OATT as modified by the Final Rule in this proceeding.

659. EEI and Exelon contend that the transmission provider may not be able to charge a generator under its OATT if the generator is not the transmission customer and, therefore, generators should be able to include standardized imbalance terms in agreements with eligible customers prior to providing service. Exelon suggests that the Commission both adopt in the *pro forma* OATT a standard imbalance penalty structure and direct transmission providers to include the same terms and conditions in their interconnection agreements with generators. TAPS suggests on reply that each generator could simply be required to sign a service agreement that requires it to comply with the generator imbalance provisions of the transmission provider's OATT. Unless the *pro forma* OATT governs both generator and load imbalances, TAPS argues that it would be impossible to implement and enforce the Commission's prohibition against charging both energy and generator imbalances for a single transaction.

660. ICNU argues on reply that the Commission should adopt less restrictive imbalance charges for retail access customers or, at a minimum, continue to recognize that the standard energy imbalance charge needs to be modified to accommodate direct access customers. ICNU asks the Commission to modify its proposed imbalance provision to reflect the unique characteristics of direct access customers by adopting wider imbalance bandwidths and/or waiving the more punitive adders associated with higher deviations.

661. Several entities assert that the proposed imbalance reform should not apply to RTOs. Exelon requests that the Commission explicitly state that these rules do not apply in regions that have organized markets, such as PJM, that obviate the need for imbalance penalties. They contend that within organized markets, an imbalance penalty rule is not necessary, as the independent transmission operators have effectively addressed the concerns that the proposed imbalance schedules are intended to address. Indicated New York Transmission Owners contend that the Commission should grant the NYISO a regional variation from the revised *pro forma* OATT with respect to imbalance charges. It contends that the existing mechanisms in ISO/RTO markets with LMP are consistent with the Commission's objectives in its NOPR and that the Commission should permit a regional variation to the NYISO. SPP states that the Commission should state that it does not intend to affect its effort to implement a real-time energy imbalance market by any final rule. SPP further contends that the Commission should clarify that its energy imbalance changes do not apply to ISOs and RTOs with organized

[393] *E.g.*, Morgan Stanley, Northwest IOUs, Steel Manufacturers Association, and TDU Systems.

[394] *E.g.*, Fertilizer Institute, Entegra, and TAPS.

markets providing for real-time energy imbalance markets. SPP believes that the Commission should view the existence of a spot energy price in organized markets as superior to penalties based on incremental costs or some multiple thereof.

662. Entegra suggests that, since many RTOs have (or are developing) separate markets for commitment costs, it may not be necessary to incorporate such costs into imbalance prices in certain RTO markets. Organizations of MISO and PJM States contend that this proposed change to Schedule 4 is not applicable in the RTO context and argue that, to the extent that the Commission's suggestions regarding the special circumstances presented by intermittent generators are applicable to RTOs, those issues are best addressed in a context other than the instant rulemaking proceeding.

Commission Determination

663. In order to increase consistency among transmission providers in the application of imbalance charges, and to ensure that the level of the charges provides appropriate incentives to keep schedules accurate without being excessive, the Commission adopts in the *pro forma* OATT imbalance provisions similar to those implemented by Bonneville. We agree with commenters that a graduated bandwidth approach recognizes the link between escalating deviations and potential reliability impacts on the system. Furthermore, we conclude that these provisions adhere to the three principles discussed in the NOPR, which we also adopt here: (1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

664. Specifically, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) will be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) will be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) will be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost for underscheduling imbalances.

665. The Commission adopts Bonneville's tariff provisions that provide that intermittent resources are exempt from the third-tier deviation band and would pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts. We believe this is consistent with the fact that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules.

666. Several commenters argue that the Commission should adopt a standard definition of intermittent resource. In order to clarify application of imbalance charges, we define an intermittent resource for this limited purpose as ''an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.'' [395] We conclude that this definition of intermittent resource properly limits the exemption from imbalance charges, without excluding certain classes of intermittent generators for which the exemption is appropriate (*e.g.*, non-weather driven intermittent resources).

667. The Commission believes that adopting a tiered approach for both energy and generation imbalances will best balance the needs of transmission providers to operate their transmission systems in a reliable manner with the needs of transmission customers to have reasonable access to those systems at just and reasonable rates. Furthermore, we conclude that the partial exemption from imbalance charges for intermittent resources appropriately reflects the special circumstances faced by such resources and, consequently, is not unduly discriminatory. Moreover, formalizing generator imbalance provisions in the *pro forma* OATT will standardize the future treatment of such imbalances from the wide variety of generator imbalance provisions that exist today in various generator interconnection agreements. Standardizing generator imbalances should lessen the potential for undue discrimination, increase transparency and reduce confusion in the industry that results from the current plethora of different approaches.

668. Several commenters debate whether the imbalance provisions adopted here should be applied to energy imbalances, generation imbalances, or both. The Commission concludes that subjecting both energy and generation imbalances to the same charges is appropriate. Energy and generation imbalances have the same net effects on the transmission system in requiring other generation to be ramped up or down to make up for the imbalance. As such, the Commission will modify the current *pro forma* OATT Schedule 4 treatment of energy imbalances and adopt a new separate *pro forma* OATT Schedule 9 for the treatment of generator imbalances, each based on the tiered structure described above. To the extent a transmission provider wishes to deviate from these revised *pro forma* provisions, it may demonstrate in an FPA section 205 proceeding that the proposed changes are consistent with or superior to the *pro forma* OATT as modified by this Final Rule. However, we note that proposed alternative provisions must comply with the three imbalance charge principles addressed in the NOPR and adopted in this Final Rule and be consistent with or superior to the specific imbalance charges set forth in the *pro forma* OATT (and discussed above).

669. Some commenters stated that the Commission should require transmission providers to establish, or permit market participants to establish, markets or pools for the netting and settlement of imbalances. As explained previously, the purpose of this rule is to strengthen the *pro forma* OATT to remedy undue discrimination and not to impose any particular market structure. If transmission providers offer to modify their OATTs to allow such pools, we will consider such proposals. But, imposing such requirements goes beyond the scope of this proceeding. The Commission therefore declines, for all these reasons, to impose the structural reforms requested by some commenters.

670. The Commission instead adopts the three-tiered approach in the *pro*

[395] *See* Docket No. RM05–10–000. We note that this definition was proposed by the Commission in the NOPR on Imbalance Provisions for Intermittent Resources. *See Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets,* Notice of Proposed Rulemaking, 70 FR 21349 (Apr. 26, 2005), FERC Stats. & Regs. ¶ 32,581 (2005).

forma OATT. As with other reforms adopted in this Final Rule, all transmission providers must submit compliance filings containing these *pro forma* tariff provisions. Transmission providers with previously-approved tariff provisions governing imbalances that no longer conform to the *pro forma* OATT, as revised in this Final Rule, may seek renewed approval of those tariff deviations in accordance with the procedures described in section IV.C above, demonstrating that the alternative imbalance charge structures are consistent with or superior to the reformed *pro forma* OATT. With respect to the concerns raised by ISOs and RTOs, we agree that LMP-based markets can provide an efficient and nondiscriminatory means of settling imbalances and, as indicated in the NOPR, we are not proposing to redesign ISO/RTO markets in this rulemaking. Nevertheless, ISOs and RTOs must follow the procedures described in the Applicability section for seeking approval of deviations that are consistent with or superior to the *pro forma* OATT.

671. We do not, however, abrogate existing generator imbalance agreements between transmission providers and their customers. These agreements have been negotiated between willing parties, and the Commission will not re-open them generically in this proceeding. To the extent a particular party desires to amend an existing generator imbalance agreement in light of the reforms we adopt in this Final Rule, that party may exercise whatever rights it may have under the agreement or FPA section 206.

672. With regard to WECC's frequency-response concerns, we agree that a generator should be excused from imbalance penalties that occur due to directed reliability actions by generators to correct frequency. It would not be appropriate to assess imbalance charges on generator deviations that are associated with supporting system reliability by responding to frequency deviations as directed by the transmission provider or general reliability requirements. As such, if a response from a generator (particularly in the West) is required to prevent frequency decay and the corresponding deviations from the generator's schedule would cause additional imbalance penalties, the transmission provider should exempt the generator from those penalty charges.

b. Intentional Deviations

NOPR Proposal

673. In the NOPR, the Commission noted that the Bonneville imbalance provision allows for greater charges when a customer has an ''intentional deviation.'' [396] The Commission sought comment on whether the *pro forma* OATT imbalance provision should provide for similar penalties for behavior that represents deliberate reliance on the transmission provider's generation resources, as opposed to scheduling errors, with such penalties being subject to prior notice and approval by the Commission and based on the facts and circumstances of the individual transmission provider.

Comments

674. Several entities contend that higher imbalance charges and penalties for deliberately leaning on the grid can be appropriate.[397] Imperial supports an imbalance provision that allows for greater charges for persistent or patterned deviations. Pinnacle agrees that deliberate reliance on the transmission provider's generation resources is inappropriate and could adversely affect the reliability of the transmission system, but they are unsure if such an intentional deviation could be proven. Imperial also expresses concern that the burden to prove the intent of the generator will fall on transmission providers and that, in reality, transmission providers may face an uphill battle to prove a generator's deviation was intended. South Carolina E&G and Imperial request that the Commission provide a specific process for imposing such penalties, including what procedures should be followed if a transmission provider seeks to have the Commission impose such penalties.

675. Several entities oppose penalties for intentional deviations or suggest modifications. Constellation supports an elimination of the separate penalty structure for customers deliberately leaning on the system. Constellation and Grant believe that a graduated percentage adder/discount will provide the right incentives and disincentives without the need for an intentional deviation provision. If deviation costs are properly calculated, Morgan Stanley contends that requiring those who deviate to pay the full marginal cost of that deviation would result in fair allocation of cost responsibility and sufficient stability of system operations as a result of both cost and risk avoidance by participants. TDU Systems argue that the Commission should eliminate the 100 mill per kWh floor for penalties for intentional deviations.

Commission Determination

676. The Commission recognizes the need to provide transmission customers with the appropriate incentives not to intentionally dump power on the system or lean on other generation. We do not believe, however, that separate penalties for intentional deviations need to be generically imposed in the *pro forma* OATT. The tiered imbalance penalties adopted in this Final Rule generally provide a sufficient incentive not to engage in such behavior. Proposals to assess additional penalties for intentional deviations will continue to be considered on a case-by-case basis, subject to a showing that they are necessary under the circumstances. We note that any such tariff provisions must include clearly defined processes for identifying intentional deviations and the associated penalties.

c. Calculation of Incremental Cost

NOPR Proposal

677. With respect to the pricing of energy and generation imbalances, the Commission stated in the NOPR its belief that charges based on incremental costs or multiples of incremental costs would provide the proper incentive to keep schedules accurate without being excessive. The Commission proposed that incremental cost be defined to include both energy and commitment [398] costs, to the extent additional commitments are needed.[399]

[396] *See* 2006 Transmission and Ancillary Service Rate Schedules, approved in *United States Dep't of Energy—Bonneville Power Administration,* 112 FERC ¶ 62,258 (2005). The Bonneville tariff provides that ''For any hour(s) that an imbalance is determined by [Bonneville] to be an Intentional Deviation: (1) No credit is given when energy taken is less than the scheduled energy, (2) When energy taken exceeds the scheduled energy, the charge is the greater of: (i) 125% of [Bonneville's] highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.'' An ''Intentional Deviation'' is defined as ''a deviation that is persistent during multiple consecutive hours or at specific times of the day,'' a ''pattern of under-delivery or over-use of energy,'' or ''persistent over-generation or under-use during Light Load Hours, particularly when the customer does not respond by adjusting schedules for future days to correct these patterns.'' *Id.* at 46.

[397] *E.g.,* Imperial District Irrigation, Progress Energy and Ameren.

[398] The Commission noted that ''capacity commitment'' is generally defined as the generating capacity committed by a utility to provide capability for another utility to attain its reserve level. *See, e.g., Central & South West Services, Inc.,* 48 FERC 61,197 at 61,731 n.9 (1989).

[399] The Commission proposed defining incremental cost, based on its decision in *Consumers,* as the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and

The Commission sought comment on how such charges should be calculated, as well as how they would be applied to transmission customers. The Commission sought further comment as to how additional demand and energy costs, if incurred in responding to imbalances, such as redispatch, commitment, or additional regulation reserves, should be appropriately reflected in the calculation of imbalance charges and which customers should be charged for such costs.

Comments

678. Several entities argue that incremental pricing for both energy imbalances and generator imbalances should reflect the full incremental costs incurred by the transmission provider (*e.g.*, such as redispatch costs, capacity commitment costs or additional regulation reserve costs) resulting from the imbalance.[400] Allegheny questions whether the *Consumer's* definition is appropriate because ''the last 10 MW'' requirement is independent of the time of the scheduling deviation. Allegheny contends that the definition should be modified such that it specifically addresses the incremental dispatch to supply the transmission provider's load ''in the hour in which the imbalance occurs.''

679. Entergy argues that imbalance pricing on an hourly basis does not capture all of the costs and reliability risk to the transmission provider of over- and under-deliveries. Entergy states that the real-time regulation burden imposed by IPPs is similar to the real-time regulation burden imposed by loads, and loads are charged for this cost through a transmission provider's Schedule 3 Regulation and Frequency Response Service. Entergy asserts that the NOPR does not propose any recovery mechanism for the regulation burden imposed by IPPs, recognizing that Bonneville may not face significant generator regulation costs due to the rapid ramping rate and relatively low cost of hydroelectric resources. Entergy submits that its regional experience has demonstrated that generator regulation service is a necessity. Entergy states that its generator regulation service recovers charges for the generating capacity that Entergy must maintain on-line in order to respond to the moment-to-moment deviations between scheduled output and actual generation. Entergy explains that the charge compensates Entergy on a cost-basis for the generation capacity used by IPPs, while at the same time sending the appropriate economic signal that encourages generators to match their generation with their schedules.

680. In its reply comments, EEI argues that a transmission provider should be entitled to recover the cost of additional reserves needed to meet the increased reliability requirements resulting from the provision of the imbalance energy if the transmission provider generates additional energy to compensate for a load that schedules less energy than it takes or a generator that produces less energy than it schedules. EEI further contends that transmission providers should be permitted to include in their calculation of imbalance charges any other costs associated with committing a unit that is not on-line such as minimum run times, losses, *etc.*

681. Entergy opposes a single price for settling over-deliveries and under-deliveries. For transmission providers who choose to base energy and generator imbalance charges on incremental and decremental costs, Entergy requests that the Commission not adopt standardized definitions of incremental cost and decremental cost in the *pro forma* OATT. In its reply comments, Entergy further argues that a requirement that the transmission provider post incremental and decremental cost information is unfair and harmful to the market, placing the transmission provider at an unfair competitive disadvantage in the market. Duke on reply proposes that System Incremental Cost (SIC) be used to price both over-deliveries and under-deliveries. Duke defines SIC to mean the incremental expense, measured in dollars per megawatt hour, incurred by the utility to produce or procure the next megawatt hour (MWh) of energy, after serving all of the utility's electric energy and/or capacity sales. Duke proposes that SIC shall include but not be limited to: The replacement cost of fuel; incremental operating and maintenance costs; emissions allowance replacement costs and other environmental compliance costs; the cost of starting and operating any generating units, (including costs incurred due to minimum runtimes or loading levels); purchase and interchange power costs; and all applicable taxes or assessments based on the revenues received or quantities sold.

682. Allegheny states that the Commission should clarify that the definition of incremental cost is equally applicable to intermittent generator imbalance service as well as non-intermittent generator imbalance service.

683. Pinnacle and Utah Municipals request that the Commission allow the use of alternative pricing methodologies, such as market proxy pricing methodology based on trading hubs in or adjacent to their respective control areas, where appropriate. Utah Municipals urge the Commission to make clear in the final rule that market-based pricing may be acceptable in some circumstances and to amend Schedule 4 of the *pro forma* OATT to ensure that imbalance charges are designed not only to provide legitimate incentives for accurate scheduling, but also to avoid unjustified penalties (masquerading as ''incentives''), to minimize the discriminatory impact of such charges, and to avoid penalizing behavior or results that in fact help to keep the system as a whole in balance.

684. TDU Systems believe the Commission should disallow recovery of demand charges or capacity commitment costs in any charges approved for imbalances. TAPS and TDU Systems argue that capacity required to follow load is already paid for by charges for regulation and reserves under Schedules 3, 5 and 6. TDU Systems also support that the Commission continue to apply its existing policy of imposing a heavy burden on transmission providers to justify such demand or capacity commitment charges in the context of a full base rate case, and of requiring transmission providers to develop alternative solutions for balancing schedules and loads.

685. To the extent transmission providers are permitted to include commitment costs in negative imbalance charges, Entegra believes that additional monitoring would be needed, to include posting of hourly imbalance charges, even if with a lag of a day or so. Suez Energy NA contends that the Commission should require a transmission owner to support its incremental cost filing on the basis of Form No. 423 data and actual operations of the selected units, based on operational data as reported in utilities Continuous Emission Monitoring reports.

686. EEI argues that since Schedule 3, 5 and 6 charges recover the costs of capacity based on test year data, they would not recover the additional costs of reserves that transmission providers incur to compensate for their customers' failures to match their schedules and their loads or generator output, and they also do not recover other commitment costs such as start-up costs or minimum run times. EEI argues that if transmission providers could not recover such costs through imbalance

maintenance costs, and purchased and interchange power costs and taxes.

[400] *E.g.*, Allegheny, Ameren, Indicated New York Transmission Owners, and FirstEnergy.

charges, they would not be able to recover them at all.

Commission Determination

687. The Commission concludes that it is appropriate to define incremental cost, for purposes of the tiered imbalance provisions adopted above, as the transmission provider's actual average hourly cost of the last 10 MW dispatched to supply the transmission provider's native load, based on the replacement cost of fuel, unit heat rates, start-up costs, incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

688. In deriving such charges, we note that the Commission proposed in paragraph 244 of the NOPR that incremental cost be defined to include both additional energy and commitment costs. The Commission also sought comment on how additional demand and energy costs, such as redispatch, commitment, or additional regulation reserves, would be appropriately recovered if incurred in responding to imbalances.

689. The Commission finds that it is appropriate, through the definition of incremental cost, to allow for recovery of both commitment and redispatch costs while excluding the cost recovery of additional regulation reserve costs. Commitment and redispatch costs shall be accommodated as a part of the hourly cost of the last 10 MW dispatch and in the start up cost portion of the definition. The Commission concludes that excluding additional regulation costs as a general matter is appropriate since much of those costs would be demand costs.[401] We believe including charges for unit commitment costs (*e.g.*, start-up and minimum load costs) and O&M costs is necessary to ensure that both energy and generation imbalance charges reflect the full incremental costs incurred by the transmission provider. We emphasize, however, that such costs should only be the additional costs incurred by the transmission provider due to the imbalance. If applicable, start-up costs should be allocated *pro rata* to the offending transmission customers based on cost causation principles.

690. If the transmission provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the transmission provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs. To address Entergy's concern that the real-time regulation burden imposed by IPPs is similar to the real-time regulation burden imposed by loads, we will allow transmission providers to propose separate regulation charges for generation resources selling out of the control area and consider such proposals on a case-by-case basis. We believe that the other demand costs of providing imbalance service are already being provided under Schedule 3, 5, and 6 charges.

691. In responding to Allegheny's comments, we clarify that the definition of incremental cost is equally applicable to intermittent generator imbalance service as well as non-intermittent generator imbalance service.

692. We do not believe it appropriate to require transmission providers to use market proxy pricing to calculate incremental costs in the *pro forma* OATT. The feasibility of using market proxies must be considered on a case-by-case basis, given the characteristics of each market. If proposed, the proxy price must represent a valid alternative to the incremental cost calculation, reflecting competitive, transparent and liquid conditions similar to those that would exist in the seller's market.[402]

d. Inadvertent Energy Treatment

NOPR Proposal

693. The Commission proposed in the NOPR to continue to allow inadvertent energy to be treated differently from energy and generator imbalances, explaining that these two types of service are not comparable. The Commission noted that, given the nature of inadvertent energy and historical practices, transmission providers pay back inadvertent energy imbalances and that the Commission has accepted this practice as just and reasonable. The Commission sought comment on whether the current return-in-kind approach to inadvertent energy encourages leaning on the grid in times of shortage and, therefore, whether any reforms in this area are appropriate. The Commission asked whether pricing inadvertent energy at incremental cost (or some variant thereof) would be an appropriate disincentive and, if any reforms in this area are appropriate, whether they should be pursued under FPA section 215 as part of the review of reliability standards.

Comments

694. A number of commenters support continuing to allow inadvertent energy to be treated differently from energy and generator imbalances, agreeing that these two types of services are not comparable.[403] Allegheny argues that this historical practice makes sense because the variables germane to inadvertent interchange are beyond the control of individual transmission providers and, therefore, are best addressed in the context of reliability. Entergy notes that transmission customers have some flexibility to mitigate the deviations between their schedules and the operation of their load in real-time, while control area interchange imbalances may involve the failure of control areas to match their scheduled inflows and outflows due to contingencies occurring even in a third control area.

695. Northwest IOUs argue that there is no reason to think that there is abuse of one system leaning on another in regards to inadvertent energy, particularly in light of Control Performance Standards 1 and 2 and other protocols for balancing flows across interconnections. Public Power Council states that in-kind return of inadvertent energy between Balancing Authorities is governed by numerous agreements and tariffs that are designed to limit the ability of one system to lean on another.

696. Sacramento states that the Commission expressed concern in other settings that generators may intentionally undergenerate during high-cost hours and make it up by overgenerating during low-cost hours under a return-in-kind approach. Sacramento contends that in kind means not only a return of energy, but a return of energy at like times and conditions and does not believe that this results in leaning. In its reply comments, Exelon requests that the Commission's imbalance penalty rules explicitly prohibit the local utility Balancing Authority operator from relying on inadvertent energy to balance its affiliated generators' schedules and thus obtaining a competitive advantage.

697. Other commenters disagree that inadvertent energy should continue to be treated differently. Exelon expresses concern that in regions without organized markets there is the potential

[401] To the extent a transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it must do so via a separate FPA section 205 filing demonstrating that these costs were incurred correcting or accommodating a particular entity's imbalances.

[402] *See RockGen Energy, LLC*, 100 FERC ¶ 61,261 (2002) (setting for hearing, *inter alia*, whether proposed market proxy price is reliable, verifiable, and also indicative of the prevailing price in liquid non-redispatch markets in the region).

[403] *E.g.*, Entergy, Allegheny, Progress Energy, Public Power Council, South Carolina E&G, PGP, and Ameren.

for local utility balancing authority operators to seek to avoid paying deviation charges by favoring their own generators over merchant generators or by using inadvertent energy to balance their schedule. Exelon argues that a balancing authority operator could maintain system balance by choosing to order its affiliated generators to deviate from the schedule and thereby allow its affiliated generator to avoid deviation charges that the merchant generator could not avoid. If the local utility balancing authority operator relies on inadvertent energy to balance its affiliated generators' schedules, Exelon contends it is using an option that is unavailable to other generation resources and obtains a competitive advantage.

698. TDU Systems argue that energy imbalances and inadvertent interchange may occur for many of the same reasons, *e.g.*, telemetry failure, meter error, generator governor response to system problems, human error, and under- or over-supply of generation. TDU Systems state that deviations between load and supply, whether in the form of energy imbalances or inadvertent interchange, require adjustment or compensation, but there is no reason why the form of that adjustment or compensation should be different among transmission users. TDU systems explain that NERC's Final Report of the Control Area Criteria Task Force describes inadvertent interchange as one of the ''strong incentives'' driving the newer market participants, such as independent generators, to become control areas, and driving existing control area operators to retain their functions.

699. TDU Systems explain that as the Commission acknowledged in Order No. 2000, for transmission providers in RTO regions, unequal access to balancing options can lead to unequal access in the quality of transmission service. TDU Systems oppose deferring consideration of inadvertent interchange issues until the Commission's order in the Mandatory Reliability Standards rulemaking proceeding in Docket No. RM06–16–000. TDU Systems argue that the Commission should place energy imbalance service on a footing as nearly comparable to inadvertent interchange as feasible by allowing like-kind exchanges of energy, at the incremental cost of their own supply portfolio, to remedy imbalances in lieu of the present paradigm of punitive charges.

700. TDU Systems also argue that the Commission should require comparability between transmission providers and transmission customers by imposing charges for inadvertent interchange at the suppliers' incremental cost. FirstEnergy believes that the Commission should establish a tiered penalty structure that, similar to the Bonneville method discussed by the Commission, levies penalties based on the severity of the inadvertent energy violation. TDU Systems state that currently there are no penalties for under-supply even when one control area could be deemed to be intentionally ''leaning'' on the grid to arbitrage energy market prices; but there should be.

701. FirstEnergy argues that a nationwide process should be established by the Commission to eliminate regional differences in the treatment of inadvertent energy. Constellation asks the Commission to require that transmission providers specifically separate imbalances from inadvertent energy and closely track and report the two.

Commission Determination

702. As stated in the NOPR, the Commission finds that inadvertent energy is not comparable to energy and generation imbalances and, therefore, we will continue to allow inadvertent energy to be treated differently from energy and generation imbalances. Inadvertent energy represents the difference between a control area's net actual interchange and the net scheduled interchange. It is caused by the combined effects of all the generation and loads in the control area and generation and loads outside of the control area. Variables affecting inadvertent interchange often depend on the actions or the omissions of utilities other than the individual transmission providers and are distinct from those resulting in energy and generation imbalances.

703. We also note that management of inadvertent energy is needed to adhere to NAESB standards. Historically, transmission providers have paid back inadvertent interchange imbalances in kind, which has not, as a general matter, proven to be problematic. Our primary concern with respect to inadvertent energy is to avoid incentives that could degrade reliability. To date, the return-in-kind approach has proven to be adequate as a general matter. However, if there is evidence that it is no longer sufficient to maintain reliability, or is allowing certain entities to lean on the grid to the detriment of other entities, the Commission has authority under FPA section 215 to direct the ERO to develop a new or modified standard to address the matter.

e. Netting/Crediting of Energy and Generator Imbalances

NOPR Proposal

704. In the NOPR, the Commission sought comment on whether or not it is appropriate to allow a transmission customer to net energy and generator imbalances for a particular transaction within a single control area to the extent they offset.[404] The Commission asked whether the potential to allow netting for offsetting imbalances contradicts the principle of encouraging good scheduling practices. The Commission sought further comment on what would be a reasonable percentage to net without concerns that allowing such netting would lead to reliability concerns from using unscheduled transmission or would cause redispatch costs by the transmission provider.

705. The Commission also proposed to add provisions to schedule 4—Energy Imbalance Service and schedule 9—Generator Imbalance Service of the *pro forma* OATT to reflect the Commission's policy that a transmission provider may only charge a transmission customer for either hourly generator imbalances or hourly energy imbalances for the same imbalance, but not both.[405] The Commission explained that this policy only applies to a transmission customer that otherwise would be charged for both generator imbalances and energy imbalances for the same imbalance occurring within the same control area.

Comments

706. A number of entities believe that transmission customers should be permitted to net energy and generator imbalances to the extent that such imbalances offset.[406] Ameren and FirstEnergy assert that netting better reflects the impact of imbalances. Morgan Stanley argues that allowing such netting provides a clear competitive benefit because it would allow competitive suppliers to offer a load following service in competition with the transmission provider. Sacramento agrees that netting of offsetting imbalances should be allowed

[404] For example, the Commission noted that a transmission customer scheduling 100 MWh over an hour, but with a load of 120 MWh, would face an imbalance of 20 MW. The Commission questioned whether there should be a net charge if the customer also dispatched its generation to the same 120 MWh. Similarly, what if a transmission customer schedules 100 MWh, but has a load of 80 MWh and dispatches its generation to 80 MWh?

[405] Imbalance Provisions Proceeding at 32,123 note 19 (*citing Niagara Mohawk*, 86 FERC ¶ 61,009 at 61,028).

[406] *E.g.*, Ameren, FirstEnergy, Xcel, Suez Energy NA, Morgan Stanley, Sacramento, TDU Systems, and Utah Municipals.

provided the transmission customer relies on reasonable load forecasts.

707. Utah Municipals and Steel Manufacturers Association argue that the Commission should impose charges based on netted imbalances, both for each customer and across the system as a whole. PGP contends that there is no reason to charge for both imbalances if a generator overruns during the same hour when a load overruns, so long as the overruns cancel out within a given control area. Steel Manufacturers Association contends that the Commission should incorporate control area-wide netting of imbalances to ensure that penalties are only assessed on significant imbalances and energy imbalance charges do not become a windfall profit center for utilities. Utah Municipals suggest that the Commission provide that all imbalances be netted for each hour and that penalties (charges above or credits below actual costs) be imposed only when the system as a whole is out of balance by more than a *de minimis* amount and, even then, only on those customers whose imbalances fall in the same direction as the system imbalance. Utah Municipals note that Sierra Pacific has established a similar imbalance mechanism, which appears to be working well in its control area.

708. TDU Systems argue that the netting rules should be sufficiently flexible to allow individual customers to net their transactions within an hour, a day, a week or a month, so long as the results keep the transmission provider economically whole. TDU Systems state that the Commission should not impose a cap on the quantity of netting allowed unless the transmission provider is able to demonstrate that good system performance requires such a cap. Ameren suggests that the Commission use a tiered system for determining when imbalances can be netted, but argues that a transmission customer should not be allowed to net offsetting imbalances elsewhere on the system if the imbalance has the potential to have a significant reliability impact.

709. FirstEnergy and Utah Municipals contend that both point-to-point and network transactions should be eligible for netting. Utah Municipals and NRECA in their reply comments note that the Commission's reference to ''a particular transaction'' does not mesh with the needs and practices of network customers, who do not attempt to match portions of their total hourly loads with particular resources or ''transactions.'' Utah Municipals argue that the Commission's proposal should be modified to make clear that such customers should be permitted to net energy and generator imbalances within a single control area to the extent they offset, with no requirement that the imbalances be part of a single ''transaction.''

710. Other commenters, however, contend that transmission customers should not be permitted to net energy and generator imbalances.[407] For example, Entergy and Pinnacle believe that to permit netting of energy and generator imbalances is to undercut the very purpose of the imbalance provisions, which is to provide adequate incentives to schedule correctly and in accordance with good utility practice. Pinnacle asserts that, depending upon the location, energy or generator imbalances could create reliability or economic problems for specific areas of the system and it is important that the transmission operator know what is happening on its system and for the customer to adhere to accurate scheduling. SPP argues that allowing netting of imbalance energy between generation and load would allow price arbitrage that would be unjust and unreasonable. Indicated New York Transmission Owners assert that positive and negative imbalances do not actually offset, as the NOPR would suggest, but rather each imbalance independently places stress on the transmission system. Duke states on reply that, although several commenters support netting imbalances, not one entity supporting such netting has put forth a workable proposal for how to implement such netting where multiple generators are serving multiple loads.

711. Entergy believes that independent generators must take full responsibility for meeting their own schedules, including making adjustments to their schedules to conform them to their operation in real-time. Entergy argues that a netting approach, however, would provide an incentive for a generator to over-generate above its schedule if its load proves to be greater than expected in real-time. Entergy argues that allowing the netting of these imbalances will result in the virtual elimination of transmission schedules.

712. In instances in which transmission customers intentionally game the transmission system through netting, FirstEnergy contends that the transmission provider should have the ability to apply punitive measures through a Commission-mandated penalty process. FirstEnergy states that there appears to be no clear cut number which defines the boundary between ''good'' netting and ''bad'' netting associated with reliability issues and additional redispatch cost. During periods when transmission constraints exist, Entergy contends that it may in fact be ramping up some generators to respond to imbalances while ramping down other generation to respond to other imbalances at exactly the same time and, therefore, it is incorrect to assume that over-generation supplied by one IPP accompanied by under-generation from another IPP, even simultaneously, will have no operational effect or impose no costs on a transmission provider.

713. Allegheny believes that allowing netting of hourly deviations inside the first deviation band on a monthly basis would not allow for full recovery of imbalance costs because balances that occur in on-peak periods cost more than imbalances that occur during off-peak periods. Allegheny contends that deviations within the first band should be measured and settled financially on an hourly or, at least, an on-peak/off-peak basis, rather than allowing deviations during one part of the month to be offset by deviations in another part of the month. Indianapolis Power & Light Company argues that the imbalance volume could be within the allowed bandwidth tolerance, but still be significant enough to allow for the energy market participant to make money off of the price difference.

714. Entergy also contends that a crediting mechanism for generator imbalances would be not appropriate. Entergy asserts that such a credit would result in indifference by generators by largely immunizing them from the costs resulting from their imbalances and, as a consequence, produce economic inefficiencies and a potential threat to system reliability. Entergy argues that the current method, which provides an incentive to generators to control their own imbalances, is appropriate because generators have a desire to accurately schedule to avoid imbalances. Entergy argues that a non-offending generator in one hour can be an offending generator in the next hour and that the credit will bankroll generators so that penalty payments in one hour will be offset and paid for by penalty receipts in another hour.

Commission Determination

715. The Commission recognizes that there is a trade off between the competitive benefits of reducing imbalance charges, including allowing transmission customers to net energy and generation imbalances, and the reliability implications of the transmission provider needing to plan to accommodate such imbalances.

[407] *E.g.*, Entergy, Pinnacle, Indianapolis Power, and Indicated New York Transmission Owners.

Allowing transmission customers to net imbalances would further comparability between the transmission provider's dispatch and the transmission customers serving load. However, netting and crediting could lessen the incentive for accurate scheduling and resulting energy or generator imbalances could create reliability or economic issues for specific areas of the system if the transmission provider cannot adequately plan for such imbalances.

716. In weighing these tradeoffs, the Commission concludes that for both energy and generator imbalance services it is not appropriate to require transmission providers to allow netting of imbalances outside of the tier one band. We agree that netting can cause problems because netting would lessen the incentive for transmission customers to schedule accurately, and inaccurate schedules, in turn, could require actions by the transmission provider even when the imbalances offset. Where transmission constraints exist, a transmission customer whose load and generation was on net equal could still have an effect on the transmission system if, as Entergy contends, some generation is ramping up to respond to some imbalances while other generation is ramping down at exactly the same time. Similarly, where transmission constraints exist, if one IPP has a positive deviation from its schedule while another IPP has a corresponding negative deviation from its schedule, the transmission provider could need to ramp up generation in one area while simultaneously ramping down generation in another area. Further, we believe that flexible scheduling deadlines should allow transmission customers to change their schedules such that their loads can be accurately met and implementation of the tiered imbalance bands will ensure that charges corresponding to imbalances are just and reasonable.

f. Intra Hour Netting

NOPR Proposal

717. Under the current *pro forma* OATT, energy imbalances occur when there is a difference between the scheduled and the actual delivery of energy to a load located within a control area aggregated over a single hour. As a result, if a transmission customer is under its scheduled level for the first half of a given hour, but over its schedule the second half of the hour, there would be no imbalance charge. The Commission did not address intra hour netting in the NOPR.

Comments

718. Several commenters argue that the Final Rule should address within-hour deviations that occur when generator imbalances are calculated on an integrated hour basis.[408] If the generator imbalance is measured over an integrated hour, as is typical of the current practice, TVA asserts that significant intra-hour swings may be masked.

719. South Carolina E&G states that generators, unable to ramp precisely to the 15-minute schedules, often undergenerate in the initial part of the hour, then overgenerate in later parts of the hour, in order to integrate closer to the schedule when settled over the entire hour. South Carolina E&G contends these intentional swings burden the balancing authorities who are charged with continuously keeping Area Control Error within predefined limits. International Transmission argues that intentional swings in output can be quite severe, imposing operational strains on the system, negatively impacting the control area's ability to meet NERC Control Performance Standards, and potentially jeopardizing reliability.[409] Entergy agrees that settling hourly energy imbalances with generators does not provide adequate incentives for generators to schedule and dispatch accurately within the hour. Entergy asserts that generators have imposed significant moment to moment swings within the hour requiring it to deploy its regulating reserves in response. Entergy states that it has been increasingly difficult to meet NERC's operating criteria for control area performance without committing, and incurring the costs for, additional regulating reserves. TVA contends that all generators should be required to ensure that the instantaneous generation level equals the scheduled output. International Transmission asks that the imbalance provisions in the Final Rule address this situation by either specifying penalties that may be assessed for within-hour variations or advising that transmission providers may implement their own penalties to the extent that within-hour variations cause operational difficulties.

720. South Carolina E&G contends that allowing generator imbalance settlements over a shorter period, such as at 15-minute intervals, together with the proposed tiered charges for imbalances, would provide better, more refined incentives for generators to more closely match their scheduled deliveries and would help balancing authorities reduce Area Control Error excursions. TVA suggests generator imbalances be measured on ten-minute intervals rather than integrated over an hour. These ten-minute imbalances would not be netted against other imbalance intervals, so as to avoid the problem of encouraging undergeneration followed by overgeneration and vice versa. In addition to having generator imbalance charges for generation outside the operating bands, TVA argues that there should be a separate charge assessed based on the peak generator imbalance between the scheduled and actual generation recorded instantaneously during the clock hour to provide a further incentive for proper generator scheduling.

721. Pinnacle and Utah Municipals assert that a transmission provider should only charge hourly generator imbalances or hourly energy imbalances for the same imbalance. PGP argues that customers should pay only one charge for the net imbalance that occurs within a single control area, either energy or generation, unless congestion occurs inside a control area that requires redispatch.

Commission Determination

722. The Commission concludes that it is appropriate to maintain the *status quo* of aggregating net generation over the hour in the *pro forma* OATT. Requests by transmission providers to adopt a shorter interval will continue to be considered on a case-by-case basis.[410] The Commission acknowledges that shorter intervals may be appropriate in particular circumstances and, for this reason, declined to use a clock-hour interval in the Large Generator Interconnection Final Rule.[411] There, the Commission permitted use of an interval "consistent with the scheduling requirements of the Transmission Provider's Commission-approved Tariff and any applicable Commission-approved market structure." [412] Allowing transmission providers to continue to propose alternative intervals for purposes of the *pro forma* OATT imbalance provisions is therefore appropriate provided that such proposals are consistent with relevant market structures.

[408] *E.g.,* TVA, South Carolina E&G, and International Transmission.

[409] International Transmission provides the example that a large generator with scheduled output of 100 MW for an hour might stay at zero for the first 50 minutes of the hour and then generate 600 MW during the last ten minutes.

[410] *See Entergy Services, Inc.,* 102 FERC ¶ 61,014 (2003) and *Entergy Services, Inc.*, 111 FERC ¶ 61,314 (2005).

[411] *See* Order No. 2003 at P 335.

[412] *See pro forma* LGIA Article 4.3.1

g. Distribution of Penalty Revenues Above Incremental Cost

NOPR Proposal

723. The Commission also sought comment in the NOPR regarding the treatment of revenues the transmission provider receives above the cost of providing the imbalance service.

Comments

724. Various commenters state that the transmission provider should retain any amounts above the incremental cost of providing imbalance service. Ameren and Constellation argue such revenues should serve as a contribution towards the fixed costs of providing this service. Entergy argues that premium charges would compensate it for the administrative costs of maintaining an organization capable of providing this purchase and sales function and provide generators with an incentive to avoid mismatches between scheduled quantities and actual deliveries to Entergy. Entergy states that the Commission has previously recognized that these generator imbalance charges are analogous to the economy power rates that have historically included a percentage adder for out-of-pocket costs to recover difficult-to-quantify costs.

725. On the other hand, FirstEnergy states that the additional revenue derived from charges above incremental costs should be provided to generators and/or customers able to regulate load that provided the redispatch, commitment, or additional regulation reserves. Utah Municipals contend that the Commission should credit revenues from charges above incremental costs to accurately-scheduling customers, rather than to the transmission provider. Utah Municipals argue that the penalty portion of incremental and decremental charges and rates could be credited back to all transmission customers who incur imbalance charges and whose schedules fell within the first deviation band for that hour. Progress Energy suggests that all imbalance revenues above the cost of providing the imbalance should be distributed to all non-offending transmission customers, based on the weighted amount of each non-offending transmission customer's usage of the transmission provider's transmission system. TAPS and TDU Systems ask on reply that penalty revenues not be earmarked for retail customers.

726. Morgan Stanley believes that imbalance charges should be ''keep whole'' charges calculated and designed to reimburse whoever remedied whatever problem the imbalance caused while leaving the transmission provider financially indifferent.

Commission Determination

727. In this Final Rule, the Commission has reformed existing imbalance provisions to reduce the variety of different methodologies used for determining imbalance charges and ensure that the level of the charges provide appropriate incentives to keep schedules accurate without being excessive. We also believe that transmission providers should have a consistent method of treating revenues received through imbalance penalties or charges that are in excess of incremental cost. The Commission has previously required transmission providers with significant imbalance penalties to develop a mechanism to credit penalty revenues to non-offending transmission customers.[413] This was intended to remove the incentive of the transmission provider to hinder the development of other imbalance services that do not rely on penalties.[414] We believe it is appropriate to maintain the requirement that transmission providers credit revenues in excess of incremental costs. Therefore, as part of their compliance filings in this proceeding, transmission providers are required to develop a mechanism for crediting such revenues to all non-offending transmission customers (including affiliated transmission customers) and the transmission provider on behalf of its own customers. Such a distribution of penalty revenues recognizes that transmission providers bear the responsibility to correct imbalances and often use their own facilities to do so.

728. We acknowledge that in the *CP&L* decision, the Commission declined to allow the transmission provider to allocate a share of imbalance penalty revenues to itself as a user of the transmission system on behalf retail customers. Given the reforms to the *pro forma* OATT imbalance provisions adopted in this Final Rule, we believe the circumstances presented in that case are no longer applicable. There, the Commission based its holding on its understanding that the high imbalance penalties imposed by the transmission provider were an interim measure that were intended to be in place only until an imbalance market was developed.[415] In this Final Rule, we are adopting imbalance charges that are closely related to incremental cost and therefore minimize any incentive on the part of the transmission provider to rely on penalty revenues rather than seeking other methods of encouraging accurate scheduling. Under these circumstances, there remains no reason to exclude the transmission provider from receiving an appropriate share of penalty revenues.

3. Credits for Network Customers

729. In Order No. 888, the Commission established that network customers should be eligible for credits for customer-owned transmission facilities under certain circumstances. Specifically, section 30.9 of the *pro forma* OATT states that a network customer owning existing transmission facilities that are integrated with the transmission provider's transmission system may be eligible to receive cost credits against its transmission service charges if the network customer can demonstrate that its transmission facilities are integrated into the plans or operations of the transmission provider to serve its power and transmission customers. Section 30.9 also states that new facilities are eligible for credits when the facilities are jointly planned and installed in coordination with the transmission provider.

NOPR Proposal

730. In the NOPR, the Commission proposed severing the link in the *pro forma* OATT between joint planning and credits for new facilities owned by network customers because such linkage can act as a disincentive to coordinated planning. The Commission proposed deleting from section 30.9 the language that permits transmission providers to refuse crediting for new network customer-owned facilities that are not part of its planning process, and adding language that puts a greater emphasis on comparability. Specifically, the Commission proposed that the network customer shall receive credit for transmission facilities added subsequent to the effective date of the Final Rule in this proceeding provided that such facilities are integrated into the operations of the transmission provider's facilities and if the transmission facilities were owned by the transmission provider, they would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

731. In the NOPR, the Commission also declined to allow transmission providers as part of this proceeding to automatically add costs of credits to the transmission provider's cost of service. However, the Commission stated that a

[413] *See Carolina Power & Light Co.*, 103 FERC ¶ 61,209 at P 25 (2003) (*CP&L*); *Entergy Svcs.*, 105 FERC ¶ 61,319, *reh'g denied*, 109 FERC ¶ 61,095 at P 65–66 (2004).

[414] *See Carolina Power & Light Co.*, 97 FERC ¶ 61,048 at 61,279 (2001).

[415] *Id.*

transmission provider may propose to add an automatic adjustment clause to its rates in a filing submitted under section 205 of the FPA. The Commission also explained that it would not propose to make credits generically available to point-to-point customers that own transmission facilities, but clarified that if some facilities owned by a point-to-point customer meet all the criteria for credits, consistent with the Commission's statement in Order No. 888, the Commission would address such situations on a fact-specific, case-by-case basis.[416]

a. Severance of Credits and Planning

Comments

732. The NOPR proposal to sever the link between transmission credits and joint planning by eliminating the joint-planning requirement for credits for new facilities constructed by network customers is supported by a cross-section of the industry.[417] Exelon asserts that linking credits to network customers with coordinated planning simply creates an incentive for the transmission provider to avoid coordinated planning with the network customers so that the provider can avoid providing credits. In addition, the criterion of ''jointly planned'' with the transmission provider provides little or no value for discerning what facilities should qualify for crediting treatment. Further, Exelon argues, tying credits to joint planning is no longer necessary because the Commission's regional planning initiatives will insure that most, if not all, newly constructed facilities will be jointly planned. While EEI disagrees that the joint planning provision has acted as a disincentive to joint planning, it agrees that the coordinated planning initiatives in the NOPR has made the link unnecessary.

733. FMPA also argues that the link between credits and planning discourages joint planning because companies can avoid transmission rate credits, often for competitors, by simply refusing to jointly plan. FMPA asserts that it makes no sense to create economic disincentives to joint planning. According to these commenters, transmission lines cannot be built without some exchange of information; the joint planning link may discourage the most productive exchange and can create needless and non-productive disputation over whether joint planning did or should have taken place.

734. PGP points out, however, that credits for new facilities can only result from joint planning, because new facilities must be interconnected with the existing grid, and planning studies are necessary for that to happen. NorthWestern requests that the Commission reconsider its proposal to allow crediting of customer-owned facilities that have not been jointly planned with the transmission provider. NorthWestern contends that allowing the construction of network facilities and making a judgment after the fact is inefficient and will result in protracted litigation and facilities that do not serve the overall grid as efficiently as planned facilities. PNM–TNMP contends that the Commission's proposed action to ''sever the link'' will excuse the network customer from the coordinated planning process and can only operate at cross-purposes with the coordinated transmission planning goal that is addressed in the planning sections of the NOPR.

Commission Determination

735. The Commission adopts the NOPR proposal to sever the link in the *pro forma* OATT between joint planning and credits for new facilities owned by network customers. The proposal received broad industry support, and we agree with these commenters that the link between credits for new facilities and the requirement for joint planning can act as a disincentive to coordinated planning, which is contrary to the Commission's original objective in adopting the provision. A transmission provider has an incentive to deny coordinated planning in order to avoid granting credits for customer-owned transmission facilities.

736. We find that arguments against the proposal are largely theoretical and do not adequately take into account the coordinated planning provisions proposed in the NOPR. The coordinated planning initiatives that the Commission is adopting in the Final Rule will ensure that most, if not all, transmission facilities are planned on a coordinated basis, making it unnecessary to retain this provision of section 30.9.

b. The New Test to Determine Eligibility for Credits

737. Comments support the test for new facilities proposed in the NOPR.[418] Some argue that the test for network customer credits should continue to be whether the network customer's facilities provide capability and reliability benefits to the grid—the same standard that would apply to inclusion of the facilities in the transmission provider's cost of service if the transmission provider constructed the facilities.[419] MidAmerican states that further clarification of this point in the Final Rule would be beneficial in minimizing disputes over this issue. Likewise, MidAmerican asks the Commission to clarify in the Final Rule that such credit can be applied only to network customers taking OATT service and not to transmission customers that are under non-OATT (*i.e.*, grandfathered bundled agreements) contracts. PGP supports the new rules for granting credits to network customers, but argues implementation details should be left up to individual transmission providers.

738. Although several transmission providers support the continued use of the integration test,[420] other commenters representing municipal and public power interests ask that the Commission reconsider or clarify its application.[421] Some commenters argue that given the Commission's current interpretation of ''integration'' for transmission credit purposes and the historical application of the test, retaining any integration requirement for existing or new facilities conflicts with comparability or constitutes undue discrimination.[422] TDU Systems argue that the integration standard has encouraged discriminatory behavior by allowing transmission providers to charge network customers for transmission provider facilities constructed to serve the transmission provider's native load, while refusing to pay the network customer for comparable customer-owned transmission facilities. TDU Systems further argue that the integration test has resulted in a form of ''and'' pricing since the TDU Systems, as network transmission service customers, remain obligated to pay their load ratio share of the full transmission revenue requirement of the transmission provider's system, including the cost of transmission facilities built to serve the transmission provider's own loads.

739. NRECA questions the Commission's statement in the NOPR that, in order to satisfy the integration

[416] Order No. 888 at 31,742; Order No. 888–A at 30,271.

[417] *E.g.*, Allegheny, East Texas Cooperatives, ELCON, Exelon, FMPA, MDEA, MidAmerican, MISO, Suez Energy NA, Tacoma, TAPS, and Utah Municipals.

[418] *E.g.*, Allegheny, EEI, Exelon, MISO, Nevada Companies, South Carolina E&G, Suez Energy NA, and Tacoma.

[419] *E.g.*, Allegheny, Ameren, and MidAmerican.

[420] *E.g.*, EEI, MidAmerican, and Nevada Companies.

[421] *E.g.*, FMPA, NRECA, and TAPS.

[422] *E.g.*, East Texas Cooperatives, NRECA, TAPS, and TDU Systems.

standard, a customer ''must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid.'' [423] According to NRECA, that statement identifies three nominal requirements for customer facilities—integration, benefits and ''relied upon''—as compared to the one nominal requirement for transmission provider facilities—integration. This is fundamentally inconsistent with comparability, NRECA continues, as the Commission seems to recognize in its rationale for adding the comparability requirement to new facilities.

740. NRECA further argues that the NOPR failed to distinguish the proposed new standard in revised section 30.9 from the Commission's recent decision in *North East Texas Electric Cooperative, Inc.,*[424] which found transmission provider facilities integrated on the grounds that a showing of any degree of integration is sufficient, rejected a ''benefits'' requirement, and did not consider a ''relied upon'' requirement. East Texas Cooperatives argues that the Commission's decision in *East Texas Electric Cooperative, Inc.* v. *Central and South West Services, Inc.,*[425] applied an integration requirement for customer facility credits that was different and stricter than the standard applied to a transmission provider's facilities.

741. Regarding the application of the integration component, FMPA argues that, in order to avoid continued discrimination, it is important that the Commission reaffirm that ''additional benefits to the transmission grid in terms of capability, delivery options, and reliability'' [426] are benefits, regardless whether the transmission customers or the transmission provider (or others) benefit. Similarly, FMPA continues, the requirement that facilities must ''be relied upon for the coordinated operation of the grid'' [427] must equally include operations that serve transmission providers, customers or others.

742. Comments on the comparability component of the proposed credits test for new facilities range from several requesting that the Commission adopt a comparability-driven analysis [428] to one asking the Commission to eliminate the comparability component in favor of an integration-only analysis.[429]

743. Some commenters argue that eligibility for credits should turn in the first instance on the comparability standard set forth in the NOPR, otherwise the proposal does not eliminate undue discrimination.[430] NRECA argues that this requirement does not abandon integration because current Commission policy requires a Transmission Provider's facilities to be integrated for their cost to be rolled in to the transmission provider's annual transmission revenue requirement.[431] APPA would apply an integration test only if the transmission facilities for which the customer seeks credits are found not to be eligible under this comparability standard.

744. TAPS states that, by eliminating the integration test and simply providing that customer-owned facilities would be eligible for credits to the extent they would be included in the transmission provider's rate base if they were owned by the transmission provider (*i.e.*comparability test), the Commission would avoid litigation over what (if anything) the separate ''integration'' requirement adds in the proposed formulation. If the integration terminology is retained in section 30.9, TAPS argues that the Commission at least should clarify that the new integration test is truly different from the old integration test and cannot properly be read as limiting the comparability requirement and that the Commission will not follow precedents developed in credits cases decided under the original section 30.9.

745. To provide a comparability baseline and eliminate the need for an integration test, APPA recommends that transmission providers provide a detailed inventory of the existing facilities owned by transmission provider and network transmission customers that are included in their annual transmission revenue requirement. Network transmission customers could use the inventory, which would be updated annually, to assess whether they currently own transmission facilities comparable to those included in the transmission provider's transmission rate base, or to third-party transmission facilities for which credits are being provided.

746. MDEA argues that proposed section 30.9 appears contrary to comparability principles by imposing a standard for transmission facilities owned by customers that is more stringent than the one applied to the transmission provider's own facilities. In MDEA's view, the NOPR proposal is inconsistent with prior Commission precedent to the extent comparability is not required in evaluating eligibility of existing facilities owned by transmission providers for cost recovery.[432]

747. TDU Systems ask that the Commission clarify that the comparability prong will be aggressively enforced. For example, TDU Systems request that the Commission consider a bright-line voltage criterion to address comparability, rather than leaving it to the transmission provider's discretion as to whether the facilities would be eligible for inclusion in the transmission provider's annual transmission revenue requirement.

748. Arguing against the use of the comparability component, Entergy contends that it could cause significant confusion, and should in no way change the basic requirements needed to show integration of network customer facilities. According to Entergy, a network customer should be entitled to credits only when the transmission provider cannot meet the transmission provider's firm obligations without the customer's transmission facilities.

749. On reply, MDEA states that the principle of comparability requires that there be no distinction based on ownership or between existing and new facilities. It further asserts that Entergy attempts to draw a distinction between customer-owned transmission facilities needed by the transmission provider to meet the transmission provider's obligations to native load and firm transmission customers (for which credits should be available) and

[423] NRECA further notes that proposed OATT section 30.9 does not include these additional ''benefits'' and ''relied upon'' requirements. NRECA argues that these requirements cannot be part of the section 30.9, since regulatory preambles cannot vary the words of the rule, *citing Wyoming Outdoor Council* v. *U.S. Forest Service,* 165 F.3d 43, 53 (D.C. Cir. 1999) (''[L]anguage in the preamble of a regulation is not controlling over the language of the regulation itself'').

[424] 108 FERC ¶ 61,084 (2004), *reh'g denied,* 111 FERC ¶ 61,189 (2005).

[425] 114 FERC ¶ 61,027 at P 42 (2006), *appeal docketed,* No. 06–1090 (D.C. Cir. Mar. 10, 2006).

[426] NOPR at P 256.

[427] *Id.*

[428] *E.g.,* APPA, FMPA, and NRECA.

[429] Entergy.

[430] *E.g.,* APPA, East Texas Cooperatives, FMPA, and NRECA.

[431] NRECA compares *North East Texas Electric Cooperative, Inc.,* 108 FERC ¶ 61,084 (2004), *reh'g denied,* 111 FERC ¶ 61,189 (2005) (finding transmission provider facilities integrated and rolling in their cost over transmission provider objection) with *Mansfield Municipal Electric Department* v. *New England Power Co.,* 97 FERC ¶ 61,134 (2001), *reh'g denied,* 98 FERC ¶ 61,115 (2002) (finding transmission provider facilities not integrated and rolling out their cost over transmission provider objection).

[432] MDEA cites *Florida Power and Light Co.,* 116 FERC ¶ 61,013 (2006), and notes that the Commission applied principles of comparability to a transmission provider's existing facilities.

facilities that a network customer decides that it needs to meet its obligations. Entergy argues that credits should be available only for the former type of facility. According to MDEA, there is no justification for the distinction Entergy seeks to draw or the standard it proposes to apply. Network customers pay a full load ratio share of the embedded costs of the transmission grid, based on the premise that the entire grid is available and required to support network loads. In this regard, there is no difference between Entergy's native load and network customer loads. Transmission facilities required to meet network customer needs by definition are required to meet grid needs, provided that such facilities are integrated with the transmission network.

750. Several commenters ask the Commission to consider crediting mechanisms other than the NOPR proposal.[433] For example, Entergy and Exelon contend that new facilities should be eligible for credit only if determined through the regional planning process that such new facilities are needed, *i.e.*, that a measurable system capability or reliability benefit is provided. In their view, this will avoid litigation of cases addressing questions of integration. Utah Municipals argue that the Commission should not discount the potential evidentiary value of joint planning in assessing eligibility for customer credits. Taking a more expansive view, APPA argues that network transmission customers also should be able to obtain credits for transmission facilities they build pursuant to an open and collaborative transmission planning process in their region or sub-region. This additional opportunity for credits, according to APPA, would spur participation in the transmission planning process and would be superior to litigating the proper application of the integration standard.

751. Entegra argues that the Commission should make the crediting policy for network customers consistent with the Commission's policies for generator interconnection facilities, and require credits to be available for facilities that are integrated with the transmission grid, without any showing of additional benefits and irrespective of whether the service in question is interconnection service, network service, or point-to-point service. Entegra further argues that the Commission should allow customers to sell transmission credits to obtain transmission service elsewhere on the transmission provider's system. By allowing the development of a more liquid market for such credits, Entegra reasons, the Commission could increase the willingness of market participants to fund upgrades to the transmission system.

752. TDU Systems request that the Commission recognize that inequities have occurred and, if any upgrades are required to make network customers' facilities comparable (or comparably integrated), the costs of such network upgrades should be rolled into the transmission providers' rates.

Commission Determination

753. The Commission declines to adopt the credits test for new facilities proposed in the NOPR. The intent underlying that proposal was to prevent application of the integration test in a manner that exclusively benefits the transmission provider.[434] After reviewing the comments, we conclude that the proposed test may not in fact accomplish this objective. The test proposed in the NOPR may not effectively set forth the relationship of the integration standard to the comparability requirement. We therefore revise the test as follows, to more accurately reflect the Commission's intent as expressed in the NOPR: A network customer shall receive credit for transmission facilities added subsequent to the effective date of the Final Rule if such facilities are integrated into the operations of the transmission provider's facilities; provided however, the customer's transmission facilities shall be presumed to be integrated if the transmission facilities, if owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the *pro forma* OATT.

754. Under our precedent, a transmission provider's facilities are presumed to provide benefits to the transmission grid, whereas a transmission customer must make an affirmative showing that its facilities provide benefits in order to qualify for credits.[435] Under the test we adopt in this Final Rule, a transmission customer will be required to meet the integration standard under *pro forma* OATT section 30.9 in order to receive a credit for its facilities.[436] Because joint planning will no longer be required in order to obtain credits, we find that it is particularly important in this context to require a showing that a network customer's facilities provide benefits to the transmission provider's grid, *i.e.*, a transmission customer should not be eligible for credits for facilities that the network customer may use to provide service for itself but that the transmission provider does not need to use to provide transmission service to any other customer. However, to ensure comparability, a presumption of integration will be afforded to transmission customer facilities if it is shown that, if owned by the transmission provider, such facilities would be eligible for inclusion in the transmission provider's rate base.

c. Application of the New Test to Existing Facilities

Comments

755. Several commenters object to the Commission's proposal to apply the new comparability test in section 30.9 to new facilities, and not to existing facilities.[437] If the Commission requires the same integration standard for both existing and new facilities, East Texas Cooperatives ask us to specify which integration standard—the pre-existing integration standard, or the new standard that applies the integration standard comparably—applies and explain the difference and the basis for that choice. MDEA, FMPA and TAPS argue that no distinction is warranted between the treatment of new and

[433] *E.g.*, Entergy, Exelon, and Utah Municipals.

[434] See NOPR at P 256.

[435] *See e.g., North East Texas Electric Cooperative, Inc.*, 108 FERC ¶ 61,084; *East Texas Electric Cooperative, Inc.* v. *Central and South West Services, Inc.*, 114 FERC ¶ 61,027.

[436] The integration standard, in brief, requires that to be eligible for credits under *pro forma* OATT section 30.9, the customer must demonstrate that its facilities not only are integrated with the transmission provider's system, but also provide additional benefits to the transmission grid in terms of capability and reliability and can be relied on by the transmission provider for the coordinated operation of the grid. *Southwest Power Pool, Inc.*, 108 FERC ¶ 61,078 at P 17 (2004) (*citing* Order No. 888–A at 30,271), *reh'g denied*, 114 FERC ¶ 61,028 (2006). This policy is premised on the principle that ''just as the transmission provider cannot charge the customer for facilities not used to provide transmission service, the customer cannot get credits for facilities not used by the transmission provider to provide service.'' *Id.* at P 20 (*citing* Order No. 888–A at 30,271 & n. 277); *accord East Texas Coop., Inc.* v. *Central & South West Services, Inc.*, 108 FERC ¶ 61,079 at P 28 (2004), *reh'g denied*, 114 FERC ¶ 61,027 (2006); *Southern California Edison Co.*, 108 FERC ¶ 61,085 at P 10 (2004); *Northern States Power Co.*, 87 FERC ¶ 61,121 at 61,488 (1999); *Florida Municipal Power Agency* v. *Florida Power & Light Co.*, 74 FERC ¶ 61,006 at 61,010 (1996), *reh'g denied*, 96 FERC ¶ 61,130 at 61,544–45 (2001), *aff'd sub nom. Florida Municipal Power Agency* v. *FERC*, 315 F.3d 362 (D.C. Cir. 2003).

[437] *E.g.*, APPA, FMPA, MDEA, NRECA, and TAPS.

existing facilities and that the same standard should apply.

756. TAPS clarifies that it is not suggesting that the standard be applied retroactively to past uses, but rather prospectively to existing facilities, with the key consideration being when the claim for credits is brought and not when the facilities are constructed. TAPS argues that it cannot be claimed that the revised standard should apply only to new facilities because the comparability requirement is new. To the contrary, TAPS contends that comparability has been the theme and bedrock foundation of the Commission's transmission open-access requirement since its inception.

757. APPA argues that the Commission effectively acknowledges in the NOPR that transmission providers have failed to plan new facilities jointly with their transmission customers for the last ten years under the current section 30.9, but offers no redress for this past discrimination.

Commission Determination

758. We conclude that the new test for determining credits will apply only to transmission facilities added subsequent to the effective date of this Final Rule. A number of customer-owned transmission facilities have been developed, and resulting credits negotiated and litigated, under the prior test which the Commission determined to be just and reasonable at the time.[438] We find no basis for revisiting the Commission's determinations in those cases in this Final Rule. On a prospective basis, however, given the increased planning and coordination we require in the Final Rule, we believe it appropriate to apply the new test for determining credits.

d. Cost of Customer Facilities Automatically Included in Transmission Provider Cost of Service Without a Rate Filing

Comments

759. Several transmission providers argue that, contrary to the Commission's proposal, credits should be added automatically to the transmission provider's cost of service.[439]

760. MidAmerican argues that requiring the transmission provider to defer including the cost of the transmission credit until its next filed transmission rate case penalizes the transmission provider's shareholders who must unfairly bear the cost of providing the credit until the next rate case. If the Commission does not allow automatic rate recovery of the incremental cost of credits, MidAmerican continues, the Commission should clarify that the customer will not be allowed transmission facility credits until the rate adjustments are filed and accepted by the Commission. MidAmerican explains that such filings would examine only the new revenue requirements to be added and should not require a general rate case for the transmission provider's entire revenue requirement. Nevada Companies likewise argues that credits should not be granted to network customers if the recovery of those credits is not provided for in the revenue requirement.

761. TAPS agrees with the Commission's conclusion that it would not be appropriate in this rulemaking to allow transmission providers to automatically add costs of credits to their cost of service, and that such costs should continue to be evaluated as part of a regular transmission rate case (or recovered through an approved formula rate). APPA expresses concern that transmission providers may attempt to use the Commission's decision not to allow them to add the costs of credits associated with customer-owned transmission facilities automatically to their costs of service as a pretext for not granting such credits in the first instance (at least until they decide to file a new rate case). APPA continues that a transmission provider's decision not to exercise the option to file under FPA section 205 a new rate case or an automatic adjustment clause should not serve as a reason to allow it to decline to provide credits.

762. EEI explains that the customary basis for not allowing single-issue rate adjustments for new transmission facilities is that while one aspect of the transmission provider's costs may have increased, others may have decreased or load may have increased. This is not the case with respect to the inclusion of the transmission costs related to customer-owned facilities, EEI continues, since the existence of customer-owned facilities does not have any impact on the transmission provider's own cost of service. EEI concludes that a transmission provider should not be forced into what is essentially re-justifying its transmission cost of service simply because a customer receives a credit for the integration of its own facilities.

763. Some commenters also address the option currently open to transmission providers to add an automatic adjustment clause to their rates through a rate filing with the Commission.[440] EEI argues that if the concept of an automatic adjustment clause is just and reasonable for one transmission provider, it is equally just and reasonable for all transmission providers, and there is no need to adopt a case-by-case approach. EEI further requests that the Commission clarify that its policy is to accept rate adjustments that incorporate the costs that transmission providers incur to provide credits related to customer-owned facilities, provided that the rate adjustment methodology is just and reasonable. MidAmerican contends that the revenue requirement of the transmission provider and those of transmission customers should not be co-mingled, rather, consistent with Commission precedent, the burden is on the transmission-owning customer to demonstrate to the Commission that its cost of service and revenue requirement used to establish the amount of the credit are just and reasonable before it can receive credits. As for nonjurisdictional entities, MidAmerican explains that they may file for a declaratory ruling from the Commission regarding their revenue requirement.

764. Allegheny argues that if the Commission continues to deny transmission providers an automatic adjustment clause for these credits, it should, at a minimum, assure transmission providers that transmission credits will be recognized as a cost of service in FPA section 205 rate proceedings.

765. Entergy argues that the Commission should recognize that any filed agreement providing for payments of credits would be subject to the filed-rate doctrine.

Commission Determination

766. We are not persuaded to generically allow automatic recovery of the costs of credits associated with integrated transmission facilities to the transmission provider's cost of service. These costs typically are considered and evaluated as part of a regular cost of service review process. Automatic recovery of the costs of credits would be contrary to our long-standing policy concerning single-issue rate adjustments, a policy we decline to modify here.[441] Nevertheless, transmission providers continue to have the option to propose an automatic adjustment clause in their rates under

[438] *See East Texas Electric Cooperative* v. *Central and South West Services, Inc.,* 114 FERC ¶ 61,027 (2006).

[439] *E.g.,* Allegheny, EEI, MidAmerican, and Nevada Companies.

[440] *E.g.,* Allegheny, EEI, Exelon, and MidAmerican.

[441] *See, e.g., City of Westerville, Ohio* v. *Columbus Southern Power Co.,* 111 FERC ¶ 61,307 (2005).

FPA section 205 to address the time lag between incurring costs associated with credits and the transmission provider's next rate case.

767. Contrary to EEI's assertions, customer credits do not warrant an exception to the Commission's general policy regarding single-issue rate adjustments. EEI argues that customer credits should be treated differently because the existence of customer owned facilities, in EEI's view, does not have any impact on the transmission providers' own cost of service. Even if true, this fact would not obviate the Commission's policy. Regardless of whether the customer credit is deemed to impact the transmission provider's own cost of service, the costs it imposes may be offset by cost decreases in other areas, by load growth, or both. Allowing single-issue rate adjustments would enable a utility to increase the total rate charged by focusing solely on a single cost element, while avoiding scrutiny of all other determinants of the rate. The Commission has an obligation to ensure the justness and reasonableness of the total rate and it would be improper to allow a utility to raise rates by selectively focusing only on particular elements of its costs, while avoiding scrutiny of other rate inputs. The Commission has refused to allow such rate treatment except in the most limited of circumstances and we find no basis for deviating from that policy in this context. As explained above, a transmission provider that wishes to add an automatic adjustment clause to its rates may seek Commission approval for its methodology in a filing submitted under FPA section 205.

e. Point-to-Point Customers Not Eligible for Credits on Generic Basis

Comments

768. Several commenters support the Commission proposal to not make credits generically available to point-to-point customers that own transmission facilities.[442] APPA argues that if the frequency of cases seeking credits for facilities owned by point-to-point customers is high, then the Commission should reconsider its decision to use a case-by-case approach.

769. Some commenters encourage the Commission to clarify that point-to-point transmission customers that pay for upgrades should be compensated if such upgrades benefit the system.[443] PGP argues that customers be given credits if they meet the same conditions as network customers who would qualify. Additionally, Entegra contends that denying credits for upgrades funded by point-to-point customers would overlook the Commission's past warnings that a customer funding any new facilities integrated with the grid should be entitled to credits because a transmission system ''cannot be dismembered'' or examined piecemeal.[444]

Commission Determination

770. The Commission adopts the NOPR proposal not to make credits generically available for point-to-point customers that own transmission facilities. As the Commission explained in the NOPR, a network customer takes a usage-based service which integrates its resources and loads and pays on the basis of its total load on an ongoing basis. The transmission provider includes the network customer's resources and loads in its long-term planning horizon and the two parties coordinate operations of their facilities through a network operating agreement. In this way, network service is comparable to the service that the transmission provider uses to serve its own retail native load, and credits for certain integrated network facilities are appropriate. The point-to-point customer, however, does not purchase integration service, nor does it sign a network operating agreement with the transmission provider. Because of the inherent differences between point-to-point and network service, we therefore decline to require that transmission providers make credits generically available to point-to-point customers that own transmission facilities. If a particular facility owned by a point-to-point customer meets all the criteria for credits, we will continue to address such situations on a fact-specific, case-by-case basis consistent with the Commission's statement in Order No. 888.[445]

f. RTO and ISO Issues

Comments

771. Several RTOs or ISOs assert that they should not be required to comply with the crediting provisions because their respective planning processes and procedures are superior to or obviate the need for those set forth in the NOPR.[446] CAISO states that it does not oppose the Commission's proposal, provided that the Commission confirms that facilities cannot be integrated into CAISO's operations unless they are under CAISO's operational control, consistent with the Commission's prior rulings.

772. In Xcel's view, an RTO has no incentive to refuse to jointly plan to avoid paying a credit and there is thus good cause to allow an RTO to deviate from the language in the *pro forma* OATT relating to joint planning of new facilities in order to be considered for a facility credit. Xcel and International Transmission argue that RTOs should be allowed to incorporate network customer-owned facilities into RTO rates in the same manner as if they were constructed by a transmission owner, while ensuring against double recovery of both revenue requirements and network credits.

Commission Determination

773. The Commission concludes that it would not be appropriate at this time to generically exempt all ISOs and RTOs from the Final Rule requirements regarding credits for network transmission customers. We will address issues relating to network transmission customers credits in the RTO and ISO context in orders addressing OATT reform compliance filings submitted by each RTO and ISO. The Commission determined previously that the existing tariffs of certain RTOs and ISOs provide opportunities for transmission customers to receive credit or the equivalent (*e.g.*, Transmission Congestion Contracts, Firm Transmission Rights or Auction Revenue Rights) for building facilities or upgrades that are consistent with or superior to Order No. 888 requirements.[447] Each RTO and ISO will have the opportunity to show on compliance that this continues to be the case given the reforms adopted in this Final Rule.

[442] E.g., APPA, Bonneville, EEI, Exelon, FirstEnergy, Nevada Companies, and TAPS.

[443] *E.g.*, FirstEnergy, Seattle, and Suez Energy NA.

[444] *Citing Nevada Power Co.*, 101 FERC ¶ 61,036 at P 8 (2002).

[445] Order No. 888 at 31,742; Order No. 888-A at 30,271.

[446] *E.g.*, Indicated New York Transmission Owners, ISO New England, PJM, and SPP.

[447] For example, NYISO's tariff provides that a facilities study will contain a non-binding estimate as to the feasible Transmission Congestion Contracts (TCCs) resulting from the construction of new facilities. There, upon completion of the transmission upgrade and the first subsequent centralized TCC auction, the NYISO will determine the incremental TCCs associated with the upgrade. *See* section 19.4 ''Facilities Study Procedures'' of NYISO's tariff. Similarly, PJM's tariff provides that an interconnection customer that undertakes responsibility for constructing or completing network upgrades and/or local upgrades to accommodate its interconnection request will be entitled to receive the incremental Auction Revenue Rights associated with such facilities and upgrades subject to conditions. *See* section 46.1 ''Right of Interconnection Customer to Incremental Auction Revenue Rights'' of PJM's tariff.

Other issues

Comments

774. East Texas Cooperatives argue that the Commission should clarify that a network customer is entitled to transmission credits for its own transmission facilities and the facilities of member utilities for which the network customer arranges and pays for network transmission services. East Texas Cooperatives explain that a recent Commission decision [448] allows transmission credits only for facilities owned by the generation and transmission cooperative (G&T) and not for its individual members, which in its view is contrary to past Commission precedent.

775. FMPA asks that the Commission affirmatively state that it will exercise its jurisdiction to ensure that public power entities are compensated for transmission investment (including joint transmission projects) in the event of dispute with jurisdictional transmission providers. FMPA explains that the proposed revisions to section 30.9 may be insufficient to address all problems that may arise, especially in regions without an RTO or an existing compensation method. NRECA asks the Commission to prohibit RTOs and ISOs from using a non-public utility's transmission facilities without compensating the entity simply because it has not joined the RTO or ISO. NRECA argues that comparable treatment requires compensation for use of a transmission owner's facilities, whether the owner is subject to Commission jurisdiction or not, and the Commission should not consider a transmission tariff to be just and reasonable if it allows unlawful trespass and conversion.

776. TAPS asks the Commission to include language in section 30.9 of the *pro forma* OATT that affirmatively states customers' eligibility for rate incentives for new facilities under recently established Commission policy. TAPS further requests that the Commission guard against a transmission provider blocking such incentive based credits by refusing to engage in joint development of transmission projects with its customers.

Commission Determination

777. The Commission finds that there is not enough evidence on the record to make a generic determination on these issues and, instead, will address them on a case-by-case basis in response to appropriate filings under FPA sections 205 and 206. With regard to incentives for new facilities, the Commission has already addressed incentives for transmission infrastructure investment in Order No. 679.[449] There the Commission identified specific incentives that it will allow when justified in the context of individual proceedings. With regard to FMPA's concerns regarding potential disputes over compensation for transmission investment by non-public utilities, we note that section 12 of the existing *pro forma* OATT contains dispute resolution procedures. This Final Rule also requires transmission providers to propose a dispute resolution process as part of the coordinated planning process. Additionally, the Commission's Dispute Resolution Service is available to assist in developing a dispute resolution process, as well as the Commission via a formal complaint filed pursuant to section 206 of the FPA.

4. Capacity Reassignment

778. In Order No. 888, the Commission concluded that a transmission provider's *pro forma* OATT must explicitly permit the voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer.[450] With respect to the rate for capacity reassignment, the Commission concluded it could not permit reassignments at market-based rates because it was unable to determine that the market for reassigned capacity was sufficiently competitive so that assignors would not be able to exert market power. Instead, the Commission capped the rate at the highest of (1) The original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment, or (3) the assignor's own opportunity costs capped at the cost of expansion (price cap). The Commission further explained that opportunity cost pricing had been permitted at ''the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two (*i.e.*, 'or' pricing is permitted; 'and' pricing is not).'' [451] In Order No. 888–A, the Commission explained that opportunity costs for capacity reassigned by a customer should be measured in a manner analogous to that used to measure the transmission provider's opportunity cost.[452]

NOPR Proposal

779. In the NOPR, the Commission noted that capacity reassignment does not appear to have developed into a competitive alternative to primary capacity since the issuance of Order No. 888. To facilitate development of this market, the Commission proposed to remove the price cap on capacity reassignment and allow negotiated rates for transmission capacity reassigned by transmission customers. The Commission explained that, because the price cap appears to have reduced customers' transmission options, removal of the cap may be warranted without a market-by-market analysis. Due to market power concerns, however, the Commission proposed to retain the price cap for capacity reassigned by the transmission provider's merchant function or its affiliates.

780. The Commission proposed to monitor the market for reassigned capacity by requiring regular OASIS postings and quarterly reports from transmission providers using information submitted by reassigning customers. First, the Commission proposed retaining the existing posting and filing requirements for reassigned capacity transactions to ensure that capacity is equally available to all customers and to protect against undue discrimination and the potential exercise of market power.[453] Second, the Commission asked several questions regarding OASIS postings and the data that should be required in quarterly reports related to capacity reassignments: (1) What information should be required in the quarterly reports and OASIS postings, *i.e.*, information about the capacity released, the original rate paid for that capacity, the price charged to the assignee for the capacity, and the term of the assignment; (2) whether other information was necessary for operational and reliability purposes; (3) whether additional reports by assignors to the transmission provider are necessary and, if so, what information should be reported by assignors; (4)

[448] *East Texas Electric Cooperative, Inc.* v. *Central and Southwest Services, Inc.*, 108 FERC ¶ 61,077 at P 21–23 (2004), *reh'g denied,* 114 FERC ¶ 61,027 at P 43–44 (2006), *appeal docketed,* No. 06–1090 (D.C. Cir. Mar. 10, 2006)

[449] *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).

[450] *See* Order No. 888 at 31,696; *pro forma* OATT section 23.1.

[451] *Id.* at 31,740.

[452] Order No. 888–A at 30,224.

[453] The existing OASIS posting requirements for reassigned capacity already require, if selling on OASIS, for sellers to include data elements such as the path name, point of receipt, point of delivery, source, sink, capacity requested, capacity granted, start time, stop time, and offer price. *See* 18 CFR 37.6(c)(5).

should the Commission establish a new quarterly reporting process with a new form, or use the existing Electric Quarterly Report procedures; and (5) how frequently should OASIS postings be made.

Comments

Lifting the Price Cap for All Transmission Customers

781. Some commenters support eliminating the price cap for reassignment of transmission capacity in the secondary market.[454] For example, EPSA states that the Commission is correct to recognize that negotiated rates are dynamic and provide a market discipline on the price for reassigned capacity. Entegra argues that the Commission's removal of rate caps on releases of natural gas pipeline capacity increased available peak capacity and facilitated the movement of capacity into the hands of those that value it most highly, proving that an uncapped capacity release market can be both competitive and result in just and reasonable rates for customers.[455] Exelon supports eliminating the price cap, but asserts that, since the transmission customer is seeking to reassign the capacity, it is likely the capacity is not useful in gaining access to load and therefore is not very valuable. BP Energy contends that transparent competition between the transmission provider (marketing primary and subscribed but unutilized capacity) and transmission customers, with monitoring by the Commission and prospective capacity purchasers, will moderate if not eliminate the potential exercise of market power and encourage the release of capacity that is not otherwise used or useful. As a result, BP Energy urges the Commission to require transmission providers to facilitate a competitive capacity reassignment process, similar to that used for capacity release on natural gas pipelines.

782. Some commenters support the proposal to retain the price cap for transmission providers and their affiliates.[456] Seattle states that the Commission is correct to continue to cap prices for the transmission provider since the transmission provider is a regulated monopoly. In its reply, Entegra states that the Commission has found that having a *pro forma* OATT mitigates but does not eliminate a transmission provider's ability to leverage its monopoly power in transmission into market power in generation markets.[457] Entegra further contends that Southern, Entergy, and other transmission providers have monopoly power in transmission markets in their service territories and without a cap would exploit that market power in the secondary market. Moreover, Entegra argues that allowing transmission providers and their affiliates to charge market-based rates for transmission capacity in the primary or secondary market would exacerbate the skewed incentives that already operate to discourage construction of much needed transmission facilities in many markets.

783. Many commenters contend that lifting the price cap for reassignment of transmission capacity only for unaffiliated transmission customers would be unreasonable.[458] For example, Entergy argues that for the wholesale markets to work all wholesale market participants, including the transmission provider's affiliated marketers, must be treated comparably under the *pro forma* OATT. EEI contends that lifting the price cap can result in a more robust secondary market for transmission capacity and will reduce any risks that transmission customers may associate with being required to purchase transmission service for five-year terms in order to obtain rollover-rights. In addition, Manitoba Hydro asserts that changing the current one-year minimum term creates additional risks for transmission customers and therefore having the ability to re-sell the transmission capacity at market-based rates would assist transmission customers to better manage the financial risks involved with holding longer term contracts.

784. Some commenters support lifting the price cap for affiliates if caps are removed for non-affiliates, but are only generally supportive of lifting the price cap.[459] If the Commission does lift the price cap, Southern argues that it should also lift the price caps for the transmission provider and its affiliates as well in order to counter efforts to corner the market and other related unforeseen consequences. MidAmerican agrees, asking the Commission to retain the cap for all transmission customers if the transmission provider and its affiliates are not allowed to resell capacity at market-based rates.

785. Several commenters argue that the Commission's justification for eliminating the price cap—namely, reducing the ability of non-affiliated customers to exercise market power in the secondary market through competition among releasing customers, monitoring the market via quarterly reports, and continuing rate regulation of primary capacity—applies to energy and marketing affiliates as well.[460] First, several commenters argue that the Standards of Conduct and existing *pro forma* OATT rules ensure that transmission provider affiliates have no more ability to obtain information about the transmission system or to reserve point-to-point transmission capacity than unaffiliated customers.[461] Entergy contends that, although the Commission correctly concludes elsewhere in the NOPR that functional unbundling and Standards of Conduct requirements, if properly enforced are sufficient to address affiliate abuse concerns, the Commission seems to assume that those same protections cannot be effective where the reassignment of transmission capacity is concerned.

786. Second, some commenters question the Commission's assertion that permitting transmission provider's energy and marketing affiliates to resell or reassign transmission capacity would give them the ability to favor their own generation.[462] For example, EEI contends that transmission providers have no control over the reassignment process, and transmission customers have complete freedom to reassign transmission capacity to any customer they choose. Entergy points out that under Order No. 888 the assignor of capacity may deal directly with an assignee and without involvement of the transmission provider.[463]

787. Third, some commenters disagree with the Commission's statement that lifting the price cap for affiliates may dampen transmission investment.[464] These same commenters argue that there is no relationship between the transmission provider's obligation to build transmission

[454] *E.g.*, Allegheny, AWEA, Constellation, EEI, Entegra, EPSA, Exelon, Morgan Stanley, PPL, Seattle, Suez Energy NA, and TranServ.

[455] *Citing Natural Gas Pipeline Negotiated Rate Policies and Practices,* 114 FERC ¶ 61,034 (2006) (Brownell, Comm'r concurring).

[456] *E.g.*, APPA, AWEA, NRECA, Seattle, TAPS, and TDU Systems.

[457] *Citing Public Service Electric & Gas Company,* 78 FERC ¶ 61,119 at 61,455 (1997) (granting market-based rate authority based in part on the adequate ''mitigation of market power'' as evidenced by a *pro forma* OATT).

[458] *E.g.*, Community Power Alliance, EEI, Entergy, FirstEnergy, Imperial, Manitoba Hydro, MidAmerican, Progress Energy, and Salt River.

[459] *E.g.*, MidAmerican, PNM–TNMP and South Carolina E&G.

[460] *E.g.*, EEI, Entergy, MidAmerican, PNM–TNMP, Progress Energy, Southern, and South Carolina E&G.

[461] *E.g.*, Community Power Alliance, Entergy, Imperial, Manitoba Hydro, Salt River, South Carolina E&G, and Southern.

[462] *E.g.*, EEI, Entergy, MidAmerican, and Progress Energy.

[463] *See* Order No. 888 at 31,697.

[464] *E.g.*, EEI, MidAmerican, and Progress Energy.

facilities to accommodate third party requests for transmission service and the ability of marketing and energy affiliates to resell unused transmission capacity at market-based rates. For example, Progress Energy and others contend that the transmission provider is obligated under the *pro forma* OATT to construct transmission facilities to meet all requests for transmission service.[465] Progress Energy and EEI contend that the transmission customer will decide to purchase secondary market transmission capacity if it meets the reasonable needs of customers so long as the capacity is priced below the higher of the embedded cost of transmission service or the cost of expansion. EEI argues that the customer can require the transmission provider to construct additional capacity to accommodate the customer's request for service if secondary market service—whether offered by the transmission provider's marketing and energy affiliates or by a third party customer—is priced above the cost of expansion. In such situations, EEI and Progress Energy contend that the cost of expansion serves as a cap on the price at which both third party customers and the transmission provider's marketing and energy affiliates can resell transmission capacity. Moreover, Entergy argues that this is the same justification that the Commission relies upon to conclude that transmission customers would not hoard secondary capacity, and it is arbitrary for the Commission to ignore that principle in concluding that a transmission provider would hoard capacity.

788. Additionally, some commenters argue that lifting the price cap for affiliates will encourage transmission investment.[466] NorthWestern contends that allowing transmission providers to collect more than their ceiling price when the market is willing to pay a higher price could further the Commission's goal of encouraging transmission investment to maintain reliability and keep pace with load growth. NorthWestern suggests that the Commission could place restrictions on the proceeds in excess of the ceiling price such that, within some specified period, the dollars must be reinvested into transmission facilities or be refunded back to customers.

789. Several commenters contend that lifting the price cap only for non-affiliates could dampen participation in the secondary market and place affiliates at a competitive disadvantage.[467] Community Power Alliance argues it is unfair for the Commission to now say that their separated marketing affiliates, which have abided by Commission rules like any other market participant, cannot now compete on an equal footing with other participants in the secondary market for transmission capacity. Rather than prohibit transmission providers' affiliates from reselling capacity, Manitoba Hydro suggests that a more equitable approach would be for the Commission to lift the price cap for all resold transmission capacity, except for transmission capacity administered by an affiliate's transmission provider.

790. To the extent the Commission adopts the proposed restriction on affiliate reassignments, MidAmerican seeks guidance on whether the transmission provider is expected to assure that the assignee is a valid eligible customer under the *pro forma* OATT. Similarly, Southern encourages the Commission to carefully identify and evaluate the possible adverse effects of lifting any reassignment price caps. Southern asserts that such effects could include expanded involvement and influence by financial players driven exclusively by profit motives and who may not be subject to Commission regulation.

791. Several commenters contend that the Commission should retain the price cap for the reassignment of transmission capacity for all customers, not just affiliates of the transmission provider.[468] APPA argues that allowing the resale of such a scarce and valuable service to those who value the capacity more highly is a recipe for undue discrimination and unjust and unreasonable transmission rates, at the expense of end-use customers. While NRECA opposes the Commission proposal to remove the price cap, NRECA would support the proposal to retain the price caps for affiliates. Similarly, TAPS supports the decision not to lift the price caps for affiliates; however, TAPS urges the Commission to rethink the NOPR's proposal to otherwise lift the price cap for non-affiliates.

792. Several commenters argue that lifting the cap for any transmission customers would encourage the exercise of market power, including hoarding, and discourage transmission investment.[469] If removal of the cap were effective in making reassignment more profitable, TAPS contends it would encourage hoarding of capacity on key paths that would run afoul of the directive in FPA section 217(b)(4) to ensure the ability of LSEs to secure long-term rights for their long-term power supply arrangements. Northwest IOUs argue that lifting the price cap would encourage non-affiliated transmission customers to buy transmission capacity at cost and resell it at market, in an effort to reduce the amount of transmission capacity available for resource development and other long-term uses. PJM argues that the final rule should include a requirement that appropriate hoarding mitigation procedures be implemented should the price cap be removed. APPA argues that, if no transmission capacity is available in the short run from the transmission provider, and an LSE needs additional capacity to serve load within the next day or week, the fact that the transmission provider could build capacity in future years at an incremental rate has little if any bearing on the price that LSE is willing to pay for the next day, week, or month to avert a looming supply problem. TVA asserts that transportation prices rose drastically during periods of high demand or constraint after the price cap for resale of gas transmission capacity was removed in Order No. 637 for everyone except pipelines and their affiliates. TVA states that this benefited entities that could afford to hold capacity, but harmed those that had to buy additional capacity on a short-term basis.

793. Alcoa and Nevada Companies argue that there is a significant potential for abuse in connection with the removal of the cap, particularly in load pockets. Alcoa argues that it is not clear at this point that there are sufficient safeguards in place to prevent and monitor the exercise of market power, something that must be assured before the cap is lifted on transmission capacity resale. Nevada Companies contend the proposal to remove the cap may actually reduce utilization of the grid, contrary to its intended purpose. For example, Nevada Companies state that transmission customers who have locked up capacity in constrained markets will likely wait to the very last minute to make that capacity available in order to drive up the price, which will often result in the capacity not being utilized if transactions cannot occur quickly enough. Some

[465] *E.g.*, EEI, Entergy and MidAmerican.

[466] *E.g.*, Entegra and NorthWestern.

[467] *E.g.*, Community Power Alliance, EEI, FirstEnergy, Imperial, Northwest IOUs, Southern, and TVA.

[468] *E.g.*, Alcoa, APPA, International Transmission, Nevada Companies, NRECA, PJM, Public Power Council, TAPS, and WAPA.

[469] *E.g.*, APPA, Nevada Companies, Northwest IOUs, NRECA, PJM, TAPS, and WAPA.

commenters contend that, like LMP in organized markets, allowing price signals via lifting the cap may not encourage transmission investment, but rather create entrenched interests that profit from the existence of congestion and oppose efforts to eliminate such congestion through transmission expansion.[470] If transmission providers are forced to purchase capacity at higher prices on the secondary market, Imperial argues that their native load customers be harmed by such higher prices, which may in turn hamper transmission expansion contrary to the Commission's stated goals for promoting transmission investment.

794. In addition, some commenters are skeptical of the Commission's assertion that existing market mechanisms are a sufficient deterrent to anticompetitive behavior.[471] WAPA and TAPS argue that, while eliminating the price cap might increase customers' transmission options, the Commission still needs to conduct case-by-case market power analyses prior to lifting the cap.[472] As a result, WAPA argues, it is critical for the Commission to identify and aggressively mitigate all transmission market power on an *ex ante* basis, rather than utilizing an *ex post* monitoring scheme as proposed in the NOPR. If the Commission lifts the price cap, certain commenters argue that the Commission should establish competitive bidding transaction standards.[473] For example, Seattle asserts that a standards organization such as NAESB will need to establish bid/ask transaction standards and reporting formats and the Commission must periodically validate the assumption that the secondary market is workably competitive.

Application of the Price Cap to Members of ISOs/RTOs

795. Some commenters request clarification that, if the Commission retains the price cap for capacity reassigned by affiliates, that it not apply to entities that have turned over control and operation of their transmission facilities to an RTO, ISO or independent entities.[474] For example, Constellation requests that the Commission clarify that the revised *pro forma* OATT does not impose the cap on affiliates of transmission owners that have turned their transmission facilities over to an RTO/ISO when they reassign transmission capacity on facilities operated by the RTO/ISO. While MISO takes no position on whether the Commission should retain its cap for stand-alone transmission providers and their affiliated customers, it argues that the cap makes no sense in the context of capacity reassignments administered by RTOs and ISOs. MISO observes that the NOPR cites affiliate preference and market power concerns as the basis for retaining the cap on reassignments by transmission providers and their affiliated customers, which MISO argues are not applicable in the RTO/ISO context. Further, MISO argues that the ownership of transmission assets in an RTO/ISO is divorced from the provision of transmission service, and RTO transmission owners are transmission customers no different from any other customer class.

796. On the contrary, APPA notes that the issue is whether the transmission customer holding transmission rights over a constrained path has the ability to exercise market power and charge unjust and unreasonable rates if the cap is lifted. APPA argues that the issue is the same in both RTO and non-RTO regions. In APPA's view, whether the public utility transmission provider has joined an RTO, does not affect the ability of its merchant affiliate to extract unjust and reasonable rents for the resale of scarce transmission rights.

Alternative Price Cap Proposals

797. Some commenters propose alternatives to negotiated pricing of transmission capacity in the secondary market.[475] While APPA supports retaining the current rate cap, it contends that firm point-to-point customers should be allowed to collect demonstrable out-of-pocket costs in addition to the maximum capped rate. Alcoa suggests that the Commission could stimulate the secondary market for transmission capacity by increasing the cap and allowing parties to charge a percentage over the original price paid. Seattle contends that the existing Commission policy could be incrementally modified to permit recovery of remarketing costs and recognize that, for many customers, the transmission right is held at a much higher per unit cost than the primary rate stated in the transmission provider's *pro forma* OATT (due in part to the fact that a customer may not use all of the capacity for which it has contracted).

798. Sacramento proposes that prices for released capacity be capped at the amortized and rate-based cost of a transmission upgrade. Seattle states that costly redirect processes, including system impact studies, may be needed to create a reassignment product that has value to other customers, given that the point of receipt, point of delivery or both typically change in a reassignment. While the current *pro forma* OATT pricing model differentiates transmission rates based on term and time of day (monthly, weekly, daily, hourly), Seattle asserts that seasonal variations in the value of transmission rights offered for short-term reassignment are also worthy of consideration, especially in a region like the Northwest, where power production varies seasonally.

799. MISO states that it believes the Commission should further strengthen its pro-competitive policy by permitting RTO/ISO transmission providers to offer firm point-to-point transmission service for drive-out/drive-through transactions at market-based rates, including ''rollover'' transactions. MISO states that the principles for allocating firm capacity on such interfaces should be the same as for reassigning capacity within an RTO: *i.e.*, permitting customers that value the capacity more highly to benefit from it. MISO asserts that allowing market participants to compete based strictly on price on external interfaces would resolve many inefficiencies stemming from the cumbersome queue administration procedures currently used on such facilities. MISO states that the final rule should encourage RTOs and ISOs to introduce such competitive practices in their footprints.

800. PGP proposes two alternative approaches. First, PGP proposes that the Commission could wait until a regional approach for pricing reassignments is developed in those areas of the country that still rely on reassignments of point-to-point capacity to create a secondary market in transmission service. Second, PGP proposes that any decision to remove the price cap could be made on a case-by-case basis after a filing by a point-to-point customer at the Commission, in which the applicant must meet standards developed by the Commission that demonstrate the lack of market power in relevant transmission or generator markets.

[470] *E.g.*, APPA, International Transmission, NRECA, Public Power Council, and Seattle.

[471] *E.g.*, Alcoa, APPA, Bonneville, TAPS, and WAPA.

[472] *Citing Farmers Union Cent. Exch., Inc.* v. *FERC*, 734 F.2d 1486, 1508–10 (D.C. Cir. 1984) (concluding that ''undocumented reliance on market forces is insufficient to satisfy the Commission's regulatory responsibilities.''); *California ex. Rel. Lockyer* v. *FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004).

[473] *E.g.*, BP Energy, Seattle, and TranServ.

[474] *E.g.*, Ameren, Constellation, SPP, and TranServ. ISO New England and PJM argue that, as providers of transmission service, they have no affiliates and likewise are not bound by the Commission's reassignment proposal.

[475] *E.g.*, Alcoa, APPA, Manitoba Hydro, PGP, Sacramento, and Seattle.

801. South Carolina E&G requests that the Commission clarify how the cap is calculated if the Commission chooses to retain the price cap. International Transmission asserts that the Commission should lift the price cap, on an experimental basis, similar to the approach followed in the natural gas industry. Similarly, WAPA recommends that the Commission either retain the price cap or institute a separate rulemaking proceeding for the purpose of establishing detailed market analysis criteria for eliminating the price cap for specific transmission segments or paths.

Posting and Filing Requirements

802. Some commenters support the proposal to require transmission providers to submit quarterly reports and make OASIS postings regarding reassignments of transmission capacity.[476] Bonneville asserts that, at a minimum, transmission customers should be required to provide a downloadable file to the transmission provider for posting on the transmission provider's OASIS that identifies the assignee, the amount of capacity assigned or transferred, the date of the offer of assignment, and the rate and duration of the assignment. Other commenters argue that transmission customers should be given greater reporting responsibility.[477] Southern contends that transmission providers should not be burdened with submitting quarterly reports and making OASIS postings based on assignment information provided to them by other assignors/assignees. Rather, Southern and EEI argue that assignment information should be filed by the respective assignors and assignees in connection with their Electric Quarterly Report filings and not by the transmission provider. PNM–TNMP contend that the Commission should prescribe specific reporting obligations and associated deadlines to the assignors and reporting obligations should also include appropriate consequences for non-compliance on the part of the assignor. Nevada Companies ask that a system be put in place to charge relevant transmission customers for the additional reporting if the transmission provider is required to do the reporting, either on the OASIS or through some other mechanism.

803. Some commenters argue that more information should be posted on OASIS beyond what was proposed in the NOPR.[478] EEI asserts that the details the transmission customers should report on the OASIS and in the quarterly reports include: The identity of the primary market seller; the identities of the secondary market seller and purchaser; the points of receipt and delivery; the term of reassigned service; the quantity of the reassigned service; and the charge for the reassignment, expressed in dollars per MW-month, week, day, or hour as appropriate. Other commenters contend that the existing quarterly report is appropriate and a new report should not be instituted.[479] TranServ argues that the existing OASIS posting template query and audit functions are sufficient and no new obligations should be required. As to frequency of OASIS postings, Seattle suggests seven days after a transaction and NorthWestern proposes that the OASIS postings be no more frequent than monthly.

804. Other commenters raise confidentiality concerns or state that business practice standards for capacity reassignment posting requirements would be required.[480] Because these negotiated rates will be market sensitive, Allegheny asks the Commission not to require reporting and OASIS posting until the term of the reassignment has expired. NAESB states that capacity reassignment, including removing the price cap and allowing negotiated rates, could require posting standards for OASIS sites and the addition of significant functions to support such postings.

805. NAESB states that capacity reassignment including removing the price cap and allowing negotiated rates could require posting standards for the OASIS site, and significant functions added to support such postings. NAESB asserts that this will require a more comprehensive standards solution, which may include data aggregation by the transmission provider, reports prepared and posted quarterly including how the information is communicated between the transmission provider and marketer for collection, submittals of quarterly reports from the transmission provider to the Commission, changes to the OASIS S&CP, and determination of informational content and design of templates. NAESB states that posting is more complicated if the transmission provider is required to post information given to it by a marketer on its non-standard products and requests Commission guidance regarding posting requirements.

Other Issues

806. Some commenters argue that price caps are not limiting capacity reassignment under the current *pro forma* OATT.[481] Williams contends that other non-price limitations on capacity reassignment, such as the requirement that the assignee utilize the same source and sink as the original customers, are the real reasons there has not been more capacity reassignment. Williams acknowledges that this bars network customers from reassigning transmission capacity and requests that Commission clarify that classification of a transmission customer as a network or point-to-point customer does not restrict the purchase or reassignment of transmission capacity. Sacramento similarly complains that one of the chief impediments to capacity reassignment is that network integration service customers are not permitted either to assign their capacity or to utilize it to make off-system sales. Sacramento contends that a point-to-point customer may utilize otherwise unused capacity to make sales ''off-system'' to third parties, while network customers cannot make full use of the transmission capacity for which they are paying.

807. Some commenters contend that timelines for the release of capacity should be clearly stated.[482] APPA argues that section 13.8 of the *pro forma* OATT provides too little time for LSEs attempting to make firm power supply arrangements to obtain even daily firm point-to-point service using the capacity left unscheduled by other firm point-to-point customers. Powerex and SPP also ask the Commission to set out clear rules, including timelines, for releasing unused transmission capacity for non-firm use to better encourage full and economically efficient use of the existing transmission grid.

Commission Determination

808. To foster the development of a more robust secondary market for transmission capacity, the Commission concludes that it is appropriate to lift the price cap for all transmission customers reassigning transmission capacity. In Order No. 888, the Commission found that allowing holders of firm transmission capacity rights to reassign capacity would help parties manage the financial risks associated with their long-term commitments, reduce the market power of transmission providers by enabling customers to compete, and foster

[476] *E.g.*, Bonneville, FirstEnergy, and PJM.

[477] *E.g.*, EEI, Entergy, Nevada Companies, PNM–TNMP, South Carolina E&G, Southern, and TVA.

[478] *E.g.*, EEI, PJM, and Seattle.

[479] *E.g.*, PJM, PNM–TNMP, and TranServ.

[480] *E.g.*, Allegheny, Morgan Stanley, NAESB, Seattle, and TranServ.

[481] *E.g.*, Powerex, Sacramento, TAPS, and Williams.

[482] *E.g.*, APPA, Powerex, and SPP.

efficient capacity allocation.[483] Over the past ten years, however, it has become clear that capacity reassignment has failed to develop into a competitive alternative to primary capacity. In particular, the price cap has served to reduce customers' transmission options and impaired the development of a secondary market for transmission capacity. In order to achieve the goals originally stated in Order No. 888, we therefore lift the price cap for reassigned capacity. We believe this will allow capacity to be allocated to those entities that value it most, thereby sending more accurate price signals to identify the appropriate location for construction of new transmission facilities to reduce congestion.

809. We decline to adopt the NOPR proposal to retain price caps for capacity resold by a transmission provider's merchant function or its affiliates.[484] After reviewing the comments submitted in response to the NOPR, and further considering our ten years of experience regulating capacity reassignments, we conclude that retaining the price caps for this portion of the market would continue to impair development of the secondary market and is not otherwise necessary to ensure just and reasonable rates. We find there are no significant market power concerns to justify retaining the price caps for any transmission customer. Indeed, the Commission did not distinguish between affiliated and non-affiliated transmission customers when it initially found in Order Nos. 888 and 888–A that excess capacity reserved could be reassigned.[485] The Commission instead placed a price cap on all reassignments of capacity out of a concern that the entire market for reassigned capacity was not sufficiently competitive.[486] We now find that market forces, combined with the requirements of the *pro forma* OATT as modified in this Final Rule, will limit the ability of assignors to exert market power, including affiliates of the transmission provider. First, competition among reassigning customers will restrict the exercise of market power. Second, the continued regulation of rates for primary capacity will act as a further check to ensure rates for reassigned capacity remain just and reasonable. Finally, the amended rules we adopt below to govern the reassignment of capacity will increase our regulatory oversight of the secondary capacity market, allowing us to effectively monitor the secondary capacity market. There is thus no need to retain the existing price caps on reassigned capacity for any market participant.

810. Our decision to lift the price caps for capacity reassignments by all transmission customers is motivated by growing concerns regarding the decrease in transmission investment and the corresponding increase in congestion costs, as described more fully in section III.C of this Final Rule. The Commission believes it is important to take every opportunity to explore more efficient use of the grid by industry participants, whether they are affiliates of the transmission provider or not. Eliminating the price cap for reassigned capacity will provide greater flexibility to respond to changing system conditions and alternatives for customers that value the capacity more highly. As commenters suggest, lifting the price cap will enhance the ability of customers that reserve long-term capacity for five-year terms in order to obtain rollover rights to resell that capacity if their needs change.[487] Other customers may determine that it is more economic to acquire reassigned capacity reflecting market rates than reserve long-term capacity. In either case, lifting the price cap will help ensure that, during peak demand periods, transmission capacity will be used by those that value it the most. Establishing a competitive market for secondary transmission capacity will thus send more accurate price signals that promote efficient use of the transmission system by fostering the reassignment of unused capacity.

811. While some commenters argue that lifting the cap encourages the exercise of market power, including hoarding, and discourages transmission investment, we find that competition among reassigning customers, continuing rate regulation of the transmission provider's primary capacity, and reforms to the secondary capacity market adopted below, combined with enforcement proceedings, audits, and other regulatory controls, will assure just and reasonable rates. The Commission discussed the possibility of transmission capacity hoarding in Order No. 888. The Commission noted that unscheduled firm capacity is available on a non-firm basis to other customers and, thus, there is little practical possibility of hoarding. Instead, the capacity reassignment provisions of the *pro forma* OATT provide an economic incentive to make that capacity available to third parties.[488] This applies even when the entity obtaining transmission capacity under the *pro forma* OATT is the transmission provider.[489] It is equally in the corporate interests of a transmission provider and its affiliates not to over-reserve or ''hoard'' transmission capacity. Under the *pro forma* OATT, the affiliate—and therefore the upstream corporate parent of the affiliate and the transmission provider—bears the cost responsibility for transmission capacity that it reserves but does not use to make wholesale sales. If the affiliate attempts to hoard transmission capacity, its upstream corporate parent loses revenues just like the non-affiliate. Like any other customer, an affiliate of the transmission provider should find it in its overall corporate interest to reassign transmission capacity to others with higher valued uses at negotiated rates.[490]

812. We reject the suggestion in the NOPR that lifting the price caps for the transmission providers' merchant function or affiliates will provide disincentives to build or expand the transmission system. Without congestion, the transmission provider's rate on file will serve as the *de facto* price cap and, if congestion exists, the ''incremental rate'' reflecting the transmission provider's cost of expanding the system should act as a price ceiling for long-term transactions. It would be unreasonable to expect a transmission customer to pay a rate for reassigned capacity that is higher than the cost of expansion when it could simply exercise its rights under the *pro forma* OATT as a cheaper alternative. To the extent there is a lag-time between the request for new transmission service

[483] Order No. 888 at 31,696.

[484] Because Order Nos. 888 and 888–A require a separation of a public utility's transmission function and its wholesale generating marketing (merchant) function, a transmission provider will take service under its OATT through its merchant function or affiliate.

[485] Order No. 888 at 31,696–97; Order No. 888–A at 30,219–25.

[486] Order No. 888 at 31,697.

[487] As explained in section V.D.3, the Final Rule extends from one year to five years the minimum term required to obtain a rollover right.

[488] Order No. 888 at 31,693.

[489] *See Southwestern Public Service Company,* 80 FERC ¶ 61,245 at 61,905 (1997).

[490] Moreover, Order No. 889 required that all public utilities establish or participate in an OASIS that meets certain specifications and comply with Standards of Conduct designed to prevent employees of a public utility (or any employees of its affiliates) engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information. The Standards of Conduct mitigate the ability of an affiliate to hoard capacity or collect rates that are inconsistent with market conditions. As a result, we are less concerned in this instance about affiliates competing on the same terms as non-affiliates. To the extent problems arise from affiliate participation in the secondary capacity market, we will revisit our decision here to lift the price caps for transmission providers and their affiliates.

and the date on which new facilities would be available, the adoption of conditional firm service and modifications to redispatch service elsewhere in this Final Rule will mitigate the exercise of market power during the interim period. We believe that the reforms to rules governing reassignments of capacity discussed below, along with associated reporting obligations, will adequately limit the ability of capacity holders to exercise market power in the limited circumstances when neither primary transmission capacity nor these additional services are available.

813. Several commenters raise concerns that lifting of the price ceiling could lead to speculative pricing. If high prices occur during periods of peak demand it is a legitimate reaction to supply and demand forces. As we explained in Order No. 637–A, ''[a] surge in the price of candles during a power outage is not evidence of monopoly in the candle market.'' [491] To the extent that capacity is not being anticompetitively withheld from the market, high prices are the competitive responses to market conditions and should result in a more efficient allocation of capacity to those customers valuing it the most and a resulting expansion of transmission facilities.

814. We emphasize that we are not deregulating or otherwise adopting market-based rates for the provision of transmission service under the *pro forma* OATT. Transmission providers will continue to be obligated to make ATC available to customers, including ATC associated with purchased but unused capacity. Transmission providers also will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity. The *pro forma* OATT therefore does not, and will not, permit the withholding of transmission capacity in an effort to exercise market power. Furthermore, the rates for transmission service provided under the *pro forma* OATT will continue to be determined on a cost-of-service basis unless the transmission provider can demonstrate, on a case-specific basis, that it lacks market power. Nothing in this Final Rule affects the obligations of transmission providers to offer service under the *pro forma* OATT at cost-based rates. The only reform being adopted concerns the resale of capacity by transmission customers. Given that traditional regulation will continue to govern the sale of primary capacity under the *pro forma* OATT, we no longer believe that cost-of-service regulation is necessary or appropriate for secondary capacity.[492]

815. As with any innovative rate program, however, the Commission will monitor the secondary capacity market to ensure that participants are not exercising market power. To enhance oversight and monitoring by the Commission, we adopt reforms to the underlying rules governing capacity reassignments. First, we require that all sales or assignments of capacity be conducted through or otherwise posted on the transmission provider's OASIS on or before the date the reassigned service commences. The Commission thus eliminates the current ability of transmission customers to assign the transmission rights to another party with subsequent notification to the transmission provider.[493] The mechanisms for negotiating a reassignment remain the same. The transmission customer may either request that the transmission provider make the capacity available on its OASIS or the transmission customer may negotiate the terms of an assignment bilaterally. In either instance, however, the resulting sale or assignment must be posted by the transmission provider on its OASIS prior to the date the reassigned service commences. We require transmission providers working through NAESB to develop appropriate OASIS functionality to allow such postings. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards.

816. Second, we require that assignees of transmission capacity execute a service agreement prior to the date on which the reassigned service commences. Under the current *pro forma* OATT, transmission customers that have executed service agreements may negotiate and implement assignments of capacity without involving the transmission provider, subject to after-the-fact reporting and posting, provided the transmission customer has a market-based rate tariff on file.[494] In order to increase our oversight of reassigned capacity, we find that all reassignments must instead be accomplished by the assignee executing a service agreement with the transmission provider that will govern the provision of reassigned service.[495] This will effectively return the specified capacity to the transmission provider for the purpose of reassignment to the assignee.[496] The assignment shall be only to the specified assignee, without any obligation that the capacity be made available to third parties, and shall not be subject to any queuing by the transmission provider since the assignee is merely accepting the assignor's already-approved service for a specified period.[497] All of the non-rate terms and conditions that otherwise would apply to the transmission provider's sale of transmission capacity continue to apply in the case of a reassignment.[498]

817. Third, in addition to existing OASIS posting requirements, we require transmission providers to aggregate and summarize in an electronic quarterly report the data contained in these service agreements. As proposed in the NOPR, the use of quarterly reports will assist the Commission in gathering data to ensure the effectiveness of market forces and regulatory requirements to mitigate the exercise of market power. The Commission directs that this quarterly report be submitted electronically in spreadsheet format

[491] Order No. 637–A at 31,595.

[492] Our findings here address the particular circumstances associated with the electric utility industry and are not intended to suggest that corresponding changes should be made to the rates for capacity release by customers of natural gas transportation capacity. Any such changes would be considered only after notice and comment and based on a record applicable to the natural gas industry.

[493] *See* Order No. 888 at 31,697.

[494] *See* Order No. 888 at 31,697 n.394; Order No. 888–A at 30,224 n.151.

[495] The *pro forma* Form of Service Agreement for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service is set forth in a new Attachment A–1 to the *pro forma* OATT.

[496] As reformed in this Final Rule, the structural mechanism for reassigning transmission capacity will be similar to the mechanism for releasing pipeline capacity. While parties may be able to negotiate the prices applicable to assigned capacity, the assignee will execute a service agreement directly with the transmission provider and, thus, there will no longer be a need for the assigning party to have on file with the Commission a rate schedule governing reassigned capacity. *See* Order No. 888 at 31,697 n. 324. The transmission provider's OATT will govern the reassigned service. The assignee will pay the transmission provider for service at the negotiated rate and the transmission provider will bill or credit the assignor with any the difference between the negotiated rate and the assignor's original rate. As noted above, however, there will be no requirement for the transmission provider to create an auction for reassigned transmission capacity similar to the pipeline capacity reassignment program, since the underlying price caps are being removed for electric transmission capacity.

[497] To the extent the assignee desires to change its points of receipt or delivery, the limitations set forth in section 23.2 shall apply.

[498] *See Commonwealth Edison Co.,* 78 FERC ¶ 61,312 at 62,336 (1997); *Boston Edison Co.,* 81 FERC ¶ 61,372 at 62,768 (1997); *Southwestern Public Service Co.,* 80 FERC ¶ 61,245 at 61,905 (1997). The non-rate terms and conditions of reassigned service will therefore conform to the *pro forma* OATT. As a result, there is no requirement to file with the Commission service agreements for reassigned transmission service.

consistent with the electronic filing system used for Electric Quarterly Reports so that it is readily accessible to the Commission and the public.[499]

818. Taken together, these reforms to the rules governing reassigned capacity will increase transparency and facilitate our monitoring of the secondary market for transmission capacity. We do not believe it is necessary to require a market power analysis as a condition to exercising the right to reassign transmission capacity. Although market power analyses are one method for ensuring that market-based rates remain just and reasonable, they are not the only method.[500] To achieve the Commission's original goals for capacity reassignment expressed in Order No. 888, we adopt a more flexible approach in this area and rely on posting requirements and other regulatory controls to ensure that rates for reassigned transmission capacity remain just and reasonable. As noted above, we find that a market power analysis is not required because transmission providers continue to be obligated to satisfy requests for service—whether out of existing capacity or new facilities—at cost-based rates. Transmission capacity therefore cannot be withheld in an effort to exercise market power. Moreover, the posting and filing requirements adopted herein provide the Commission the necessary information to ensure that, even if an entity sought to exercise market power in the secondary market, such an attempt could be effectively detected.

819. We therefore disagree with commenters who assert that lifting the cap on reassignment contradicts judicial and Commission precedent. In Order No. 637–A, the Commission explained at length why *Farmers Union*[501] and other precedent did not prevent the Commission from adopting negotiated rates for secondary capacity as part of a regulatory scheme that provides safeguards to ensure that rates remain just and reasonable.[502] The court affirmed the Commission's removal of price ceilings for short-term capacity release shippers in the natural gas market established in Order Nos. 637 and 637–A, recognizing that non-cost factors such as the need to lift price ceilings to facilitate movement of capacity into the hands of those who value it most and the negotiated rates only to the secondary market distinguished the case from *Farmers Union*.[503] The same is true here, given the non-cost factor advantages of lifting the price cap and the use of monitoring and enforcement of remedies to mitigate the exercise of market power.

820. The Commission directs staff to closely monitor the reassignment-related data submitted by transmission providers in their quarterly reports to identify any problems in the development of the secondary market for transmission capacity and, in particular, the potential exercise of market power. We direct staff to prepare, within six months of receipt of two years of quarterly reports, a report summarizing its findings. To inform our analysis, we encourage market participants to provide feedback regarding the development of the secondary capacity market and, in particular, to contact the Commission's Enforcement Hotline[504] with any particular concerns as this market develops.

821. Although several commenters argue that additional posting and filing requirements could be too burdensome and costly, the Commission does not believe this burden will be great. All capacity reassignments must be conducted or otherwise posted on OASIS and each assignee will be required to submit an executed service agreement for reassigned service. The transmission provider thus will have ready access to data necessary for the OASIS postings and electronic quarterly transaction reports. In any event, the Commission's access to this data is vital to ensure effective monitoring and oversight and, thus, we find that any burden on the transmission provider is outweighed by the need for transparency. To the extent the transmission provider incurs costs to maintain or report this information, Order No. 889 made clear that all OASIS users, including the transmission provider, pay all of the fixed costs of OASIS-related activities in wholesale rates and pay usage-related variable costs and fees.[505]

822. With regard to confidentiality concerns, the Commission finds that the disclosure of reassigned capacity information is necessary for the Commission and market participants to effectively monitor transactions for undue discrimination and preference. Consistent with our determination in Order No. 2001, where similar concerns were raised regarding disclosure of information, we believe that disclosure will promote competition and make the market operate more efficiently.[506] Moreover, public reports will provide customers with a certain level of price transparency to help them make informed decisions regarding the relative value of capacity on a particular path.

823. We decline requests to require implementation of electronic auctions for reassigned capacity. While such mechanisms are in place in RTO and ISO markets, we conclude that it would be too great a burden to impose electronic auctions on other transmission providers simply to facilitate capacity reassignments. The continued use of OASIS, combined with the posting and service agreement requirements adopted here, should be sufficient to facilitate more efficient use of the grid and mitigate the exercise of market power.

824. With regard to the requests that the Commission institute alternative specific timelines and other rules for the reassignment of capacity rights to ensure efficient use of the grid, we will not revise the rules set forth in the *pro forma* OATT. We do not have sufficient evidence in this proceeding to suggest that public utilities' existing scheduling timelines generally hinder customers from reselling unused transmission capacity or lead to capacity withholding.

825. With regard to requests for network customers to reassign transmission capacity, we affirm our finding in Order Nos. 888 and 888–A that capacity reassignments are available only to point-to-point customers.[507] Point-to-point service under the *pro forma* OATT clearly sets forth defined capacity rights and is therefore reassignable. In comparison,

[499] The transmission provider should identify capacity reassignments in the Contracts tab of the EQR using the Product Type Name ''CAPACITY REASSIGNMENT.'' All terms must be fully described and rates provided. If no Product Name adequately captures the nature of a given aspect of the capacity reassignment, the assignor may use the Product Name ''OTHER,'' but that aspect must be fully described in the Rate Description field. If that description is over 150 characters, the transmission provider may use multiple Contract Product lines to describe it. General instructions on how to file the EQR may be found at *http://www.ferc.gov/docs-filing/eqr.asp*.

[500] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines,* 74 FERC ¶ 61,076 (1996).

[501] *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1501 (D.C. Cir. 1984) (*Farmers Union*) (finding that Commission failed to justify relaxation of cost-based regulation of oil pipeline companies because it did not ensure rates would remain within the zone of reasonableness).

[502] Order No. 637–A at 31,558–72.

[503] *Interstate Natural Gas Association of America* v. *FERC,* 285 F.3d 18 (D.C. Cir. 2002).

[504] Market participants may contact the Commission's Enforcement Hotline via telephone (202) 502–8390, toll-free 1–888–889–8030, fax (202) 208–0057, or at *http://www.ferc.gov/cust-protect/enforce-hot.asp*.

[505] Order No. 889 at 31,625.

[506] *See* Order No. 2001 at P 94–129.

[507] Order No. 888 at 31,696; Order No. 888–A at 30, 223.

there are no specific capacity rights associated with network service and, thus, that service is not reassignable. Network service provides a network customer with a right to integrate its designated resources with its designated loads, in a generation pattern primarily determined by the customer. As a result, it would be difficult to determine at any moment in time exactly what portion of network service could be resold, because the network customer does not have a discrete capacity reservation and its usage of the transmission system varies as it attempts to most economically use its resources to meet its loads. To the extent an entity elects network service, it does so with the understanding that the service is not reassignable because there are no specific capacity rights to reassign.

5. ''Operational'' Penalties

a. Unreserved Use Penalties

NOPR Proposal

826. In the NOPR, the Commission proposed to clarify that unreserved use penalties apply to any circumstance where a transmission customer uses transmission service that it has not reserved.[508] Specifically, the transmission customer would be subject to an unreserved use penalty in circumstances where the transmission customer has a transmission service reservation, but uses transmission service in excess of its reserved capacity. A transmission customer also would be subject to an unreserved use penalty if the transmission customer uses transmission service where it does not have a transmission service reservation. The Commission also proposed that a transmission customer would not be subject to an unreserved use penalty in circumstances where the transmission customer inappropriately uses a network service reservation to support an off-system sale.

827. The Commission sought comment on whether the current policy that limits unreserved use penalties to twice the standard rate for the entire service period has resulted in penalties that are not just and reasonable and, if so, it sought further comment regarding provisions that would yield unreserved use penalties that are just and reasonable.

(1) Unreserved Use of Transmission Service

Comments

828. Several commenters express general support for the Commission's proposed clarification that unreserved use penalties apply to any circumstance where a transmission customer uses transmission service that it has not reserved.[509] Several commenters support the Commission's proposed clarification, but suggest that the transmission provider should only assess unreserved use penalties when a transmission customer repeatedly uses transmission service that it has not reserved.[510] For instance, PNM–TNMP believes penalty assessment should be optional and should be imposed on transmission customers that do not change their practices regarding transmission use and OATT compliance after being advised of their non-compliance.

829. Several commenters argue that transmission customers with special circumstances should not be subject to unreserved use penalties in the same manner as other transmission customers. For instance, Seattle believes unreserved use penalties can result in charges that are unjust and reasonable for intermittent resources, such as wind generators, that can not precisely schedule power in future periods, but are capable of controlling output. Seattle believes that unreserved use penalties should not apply if the transmission provider is able to operate the transmission system reliably. Seattle argues that an unreserved use penalty should only apply if scheduling parties have failed to respond to dispatchers' orders stating that system conditions necessitate curtailment of output. Southern disagrees with Seattle and states that, as a general principle, unreserved use penalties should not be based on whether reliability is threatened. TDU Systems recommend that the Commission consider treating inadvertent use of point-to-point transmission service in excess of reservations by an entity serving native load in multiple control areas as an energy imbalance in the control area in which the energy imbalance occurs, rather than an unreserved use of point-to-point service. In their reply comments, EEI and PNM–TNMP disagree with TDU Systems. EEI argues that energy imbalance charges compensate generators for the additional expense they incur to compensate for the customer's failure to schedule sufficient energy to serve its load and do not compensate the transmission provider for the use of the transmission system. EEI asserts that customers that use more transmission service than they schedule should be required to pay for that transmission service just like any other user of the system.

830. Duke opposes the Commission's proposed clarification and suggests that an effective means of deterring and punishing unreserved use of transmission service is to charge the customer for the point-to-point service necessary to support the transaction and, additionally, to make the customer subject to a civil penalty in cases of intentional or repeated unreserved use. TDU Systems argue on reply that a transmission provider should not be allowed to charge unreserved use penalties unless it employs software technology designed to identify unreserved use prior to operation.

831. Several commenters suggest modifications to the manner by which transmission providers determine when unreserved use penalties should be assessed. TDU Systems believes unreserved use penalties should only be applied with prior Commission approval after notice and opportunity for hearing in order to limit the transmission provider's discretion in applying such penalties. To encourage regulatory certainty, Seattle suggests that the Commission implement tariff provisions that state a clear basis for application of unreserved use penalties.

832. Several commenters ask that the Commission delete the proposed language added to section 30.4 of the proposed revised *pro forma* OATT regarding the unreserved use of a network resource beyond its designated capacity.[511] In the event the Commission elects to retain this language, these commenters ask the Commission to clarify the language to expressly permit use of the undesignated portion of a remote network resource under secondary non-firm service (as a non-network resource) and to preserve the customer's right to use the undesignated portion of the resource for other purposes (*e.g.*, to serve its load on systems other than the host transmission provider or to make off-system sales). In its reply comments, Duke notes that the fact that a generator is designated as a network resource for a network load on one system does not prohibit a network load on a second system from obtaining non-firm energy

[508] In the NOPR, we referred to an unreserved use penalty as an ''unauthorized use penalty.'' For the purpose of the Final Rule, we adopt the term ''unreserved use penalty'' as it more clearly articulates the nature of the penalty.

[509] *E.g.*, APPA and Bonneville.

[510] *E.g.*, MidAmerican, Southern, and PNM–TNMP.

[511] *E.g.*, APPA, TAPS, TDU Systems, and EEI Reply.

from that same generator using point-to-point and secondary network resource. Duke points out that the proposed revised section 30.4 prohibits a network customer from using its firm network service to schedule power in excess of the DNR amount. Finally, TAPS asks the Commission to modify the language added to section 30.4 so that its terms are consistent with the terms used in the rest of the *pro forma* OATT.

833. EEI recommends that a customer that takes unreserved transmission service, but that does not have a service agreement with the transmission provider, be deemed to have consented to the transmission provider's filing of a service agreement, so that the transmission provider has a basis for imposing both the prevailing OATT rate and the penalty charge on the customer. EEI also recommends that the Commission clarify that a customer that uses more transmission service than it has reserved also is subject to charges for ancillary services.

Commission Determination

834. The Commission adopts the NOPR proposal that a transmission customer will be subject to unreserved use penalties in any circumstance where the transmission customer uses transmission service that it has not reserved. Specifically, a transmission customer will be subject to an unreserved use penalty in circumstances where a transmission customer has a transmission service reservation, but uses transmission service in excess of its reserved capacity. A transmission customer also will be subject to an unreserved use penalty if the transmission customer uses transmission service where it does not have a transmission service reservation, including the situations described in the Arizona Public Service Company (APS) audit report.[512] We note that the transmission provider is subject to the same penalties when it takes transmission service under its OATT.

835. Our decision to clarify the application of unreserved use penalties will eliminate a potential source of discretion in the implementation of the *pro forma* OATT and will assist the Commission in its enforcement of the OATT obligations. The unreserved use penalty itself will help discourage disorderly use of transmission service. Charging a transmission customer for just the unreserved transmission service used, as suggested by Duke, would not provide a sufficient incentive to procure adequate transmission service, even with the threat of possible civil penalties. In addition, an operational penalty rather than a civil penalty is a more appropriate default remedy, even though certain circumstances may warrant a civil penalty in addition to an operational penalty. In most instances, an unreserved use penalty can be applied in a relatively mechanical manner. As a result, an operational penalty has a relatively low administrative burden and still provides a clear signal to transmission customers regarding the cost of non-compliance.[513] We do not agree with TDU Systems' proposal that a transmission provider be required to employ software designed to identify unreserved use if the transmission provider wants to charge unreserved use penalties. As we explain below, we adopt reforms in this Final Rule that will reduce the level of unreserved use penalties for instances of inadvertent unreserved use. For instance, we reduce the period over which a one-time inadvertent use will be penalized from one month to one day. We believe that this and other reforms are sufficient to address TDU Systems' concerns.

836. We will not adopt Seattle's suggestion to add provisions to the *pro forma* OATT that specify all circumstances that constitute use of transmission service without a transmission service reservation. Any list of transmission customer actions that would be deemed to constitute use of transmission service without a transmission service reservation will necessarily be incomplete and out-of-date given the dynamic manner by which trading patterns and practices evolve. We believe that Commission actions, such as in *APS*, will provide a sufficient guide to circumstances that constitute use of transmission system without a transmission service reservation. We also reject TDU Systems' suggestion that unreserved use penalties be applied only after Commission approval. As mentioned above, an unreserved use penalty can be assessed in a relatively straightforward manner in most cases. As a result, there will typically be little need for the Commission to become involved. That said, a transmission customer can always file a complaint with the Commission protesting an unreserved use penalty.

837. We will not exempt any class of transmission customer from the potential assessment of unreserved use penalties. We do not agree with Seattle's assertion that unreserved use penalties can result in charges that are unjust and reasonable for intermittent resources, such as wind generators, that can not precisely schedule power in future periods. Unreserved use penalties are based on the transmission capacity reserved rather than the transmission service scheduled, so an intermittent resource's inability to precisely schedule power in future periods is irrelevant, as long as the resource has reserved sufficient transmission capacity to deliver the resource's full output. We also do not agree with TDU Systems' suggestion that unreserved use of transmission service by an entity serving native load in multiple control areas should be treated as an energy imbalance in the control area in which the energy imbalance occurs, rather than an unreserved use of point-to-point service. In this regard, we agree with EEI that energy imbalance charges compensate the transmission provider for the additional expense it incurs to compensate for a transmission customer's failure to schedule sufficient energy to serve its load and do not compensate the transmission provider for the use of the transmission system.

838. We will not limit unreserved use penalties to instances where the unreserved use jeopardizes the reliable operation of the transmission system. Unreserved use penalties are intended, in part, to give transmission customers an incentive to reserve and pay for the appropriate level of transmission service so that transmission service is allocated in an orderly fashion. A transmission customer that uses unreserved transmission service requires the transmission provider to take some action to accommodate the additional use of the system. Some penalty is warranted even in those instances when the transmission provider's accommodations are sufficient to avoid curtailment of transmission service to other transmission customers. Absent a penalty in all instances, transmission customers would have an increased incentive to under-reserve transmission service, which would lead to an increase in the likelihood that system reliability would be impaired. In

[512] *Arizona Public Service Co.*, 109 FERC ¶ 61,271 at P 6 (2004) (*APS*). *APS* contained two findings that Commission audit staff characterized as unauthorized use of transmission service. In the first finding, APS's wholesale merchant function did not request and pay for point-to-point service to support some of the off-system power sales it made at trading hubs where APS system resources were directly connected. In the second finding, APS incorrectly treated the Phoenix Valley 230kV system as a single node on its transmission system. As a result, off-system sales made by generators connected to the Phoenix Valley system should have been, but were not, supported by point-to-point service.

[513] The unreserved use penalties thus work in conjunction with imbalance penalties described in section V.C.2 of this Final Rule to reduce incentives to take actions that impair the reliability of the transmission system.

addition, a transmission customer that uses more transmission service than it has reserved, even in periods when system reliability has not been impaired, has nonetheless disturbed the orderly allocation of transmission service.

839. In response to comments requesting that we remove the language added to section 30.4 of the proposed revised *pro forma* OATT regarding the unreserved use of a network resource beyond its designated capacity, we clarify our intent in modifying section 30.4. The Commission has identified instances when a transmission provider has scheduled delivery of off-system non-designated short-term purchases using transmission capacity reserved for designated network resources.[514] The intent of the language added to section 30.4 of the *pro forma* OATT was to clarify that network customers are subject to unreserved use penalties when they schedule delivery of off-system non-designated purchases using transmission capacity reserved for designated network resources. We clarify, however, that a network customer may use the undesignated portion of a remote network resource to serve network load using secondary network service and may use the undesignated portion of the resource for other non-network service purposes, such as third-party sales, as long as the network customer acquires the appropriate point-to-point transmission service. Moreover, because a transmission provider does not have to ''take service'' under its own OATT for the transmission of power that is purchased on behalf of bundled retail customers, it is free to use the undesignated portion of a remote network resource to serve its bundled retail customers.[515] If the transmission provider desires to use a remote network resource for non-native load purposes, such as third-party sales, it must acquire the appropriate point-to-point transmission service.[516]

840. In order to ensure that the transmission provider has a basis for charging an unreserved use penalty, we modify section 13.4 of the *pro forma* OATT to provide that a customer that takes unreserved point-to-point transmission service and does not have a service agreement with the transmission provider is deemed to have executed the transmission provider's form of service agreement for point-to-point service. In addition, we clarify that a customer that uses more transmission service than it has reserved is also subject to charges for ancillary services. The ancillary service charges will be based on just the period of unreserved use. For instance, if a transmission customer has unreserved use during two hours on the same day, the customer must pay the ancillary service charges for those two hours, rather than for the entire day. This modification is appropriate, as the transmission provider is entitled to compensation for the ancillary services it provides when it provides transmission service. We also will modify section 3 of the *pro forma* OATT to reflect this rule.

(2) Treatment of Inappropriate Use of Network Service as an Unreserved Use of Point-to-Point Transmission Service

Comments

841. A few commenters argue that a transmission customer that inappropriately uses a network service reservation to support an off-system sale should be subject to unreserved use penalties.[517] Other commenters request clarification or modifications to the Commission's proposal regarding the treatment of transmission customers that inappropriately use a network service reservation to support an off-system sale. TAPS asks the Commission to clarify that a transmission provider that inappropriately uses network service to support an off-system sale is required to pay for point-to-point service to support the off-system sale and potentially is liable for civil penalties, as the Commission proposed in the NOPR. Suez Energy NA suggests that an affiliate of the transmission provider that violates network tariff provisions by making unauthorized sales should also disgorge unjust profits from such sales. TDU Systems urges the Commission not to impose civil penalties for inadvertent use of network service by an LSE when it serves its own native load on a neighboring system.

Commission Determination

842. The Commission declines to adopt the NOPR proposal to exempt a network customer or transmission provider that inappropriately uses network transmission service to support off-system sales from unreserved use penalties. As mentioned above, one of the purposes of unreserved use penalties is to encourage orderly use and acquisition of transmission service. A network customer or transmission provider that inappropriately uses network transmission service to support off-system sales potentially uses or acquires transmission service that should be allocated to other transmission customers. In addition, the network customer or transmission provider has not paid for transmission service as required. Therefore, we conclude that a network customer or transmission provider inappropriately using network transmission service to support off-system sales should be subject to unreserved use penalties. We will evaluate the appropriateness of civil penalties in addition to unreserved use penalties on a case-by-case basis and will not exempt, as a matter of general policy, inadvertent use of network service by an LSE when it serves its own native load on a neighboring system as suggested by TDU Systems. A network customer or transmission provider that inappropriately uses network transmission service to support off-system sales also may be required to disgorge unjust profits from such sales, as the Commission may determine on a case-by-case basis.

(3) Penalty Rate for Unreserved Use of Transmission Service

Comments

843. Transmission providers generally assert that the Commission's current policy of limiting unreserved use penalties to twice the standard rate for the entire service period has yielded just and reasonable rates.[518] EEI contends that if the customer is required to pay an unreserved use charge only for the period of unreserved use, the customer would have an incentive to reserve service for less than its maximum expected use and simply pay unreserved use charges in the hours in which it exceeds that usage. EEI concedes, however, that the maximum period for which the unreserved use charge should be assessed is one month. For example, EEI acknowledges that it would be unreasonable to charge a customer that takes yearly service a penalty for an entire year because of, for instance, a single hour of unreserved use. In addition, EEI suggests several modifications to the current unreserved use penalty policy. EEI suggests the Commission include, in the *pro forma* OATT, provisions stating that the penalty charge for unreserved use of transmission service is equal to twice the standard rate for transmission service. EEI recommends that the Commission establish a policy that a

[514] *See MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005); *PacifiCorp*, 118 FERC ¶ 61,026 (2007).

[515] *See* Order No. 888–A at 30,216–17.

[516] *See id.* at 30,217.

[517] *E.g.*, APPA and PNM–TNMP.

[518] *E.g.*, EEI, Bonneville, MidAmerican, Nevada Companies, and PNM–TNMP Reply.

customer that uses transmission service without a reservation must pay a penalty equal to twice the rate for transmission service for the greater of the period of unreserved use or one month.

844. Transmission customers generally assert that unreserved use penalties should be limited to twice the standard rate for the period of unreserved use.[519] Transmission customers who take this position argue that using the service period rather than the period of unreserved use as the basis for the penalty charge discriminates against transmission customers with longer term transmission service reservations.[520] For instance, AWEA believes that applying an unreserved use penalty based on the reservation period rather than the period of unreserved use has resulted in charges that are not just and reasonable. AWEA asserts that such a policy would also be discriminatory because, if the customer causing the unreserved use had made a shorter reservation, its penalty would be much lower. TDU Systems argue in its reply comments that there is little to be gained from charging inadvertent unreserved use more than twice the standard rate for the period of unreserved use.

845. Several commenters suggest that unreserved use penalty charges greater than twice the standard rate for the entire service period should be limited to instances of intentional unreserved use.[521] Nevada Companies note that there are some marketing entities that are consistently abusing the current policy and recommends that the Commission consider more severe penalties for continuous carelessness in tagging or a repeated pattern of unreserved use of the transmission system. Southern believes the transmission provider should be permitted to charge increased unreserved use penalties if a transmission customer consistently uses transmission services it has not reserved. TDU Systems disagree on reply comments, arguing that a penalty equal to twice the applicable charge is sufficient to deter unreserved use of transmission service.

Commission Determination

846. We will continue giving transmission providers discretion in setting their unreserved use penalty rates, although those rates will need to be consistent with this Final Rule. Penalty charges must be based on the period of unreserved use rather than the period for which service is reserved, subject to the following principles. First, the unreserved use penalty for a single hour of unreserved use will be based on the rate for daily firm point-to-point service, even if the transmission provider has a rate for hourly firm point-to-point transmission service on file. Second, as a general rule, more than one assessment for a given duration (*e.g.*, daily) will increase the penalty period to the next longest duration (*e.g.*, weekly). The unreserved penalty charge for multiple instances of unreserved use (*i.e.*, more than one hour) within a day will be based on the rate for daily firm point-to-point service. The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week would result in a penalty based on the charge for weekly firm point-to-point. The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month will be based on the charge for monthly firm point-to-point.[522]

847. Our determination is based, in part, on agreement with those commenters arguing that using the period for which a transmission customer has reserved service rather than the period of unreserved use as the basis for the penalty charge discriminates against transmission customers with longer term transmission service reservations. We are mindful, however, that basing unreserved use penalties on only the period of unreserved use could give the transmission customer an incentive to reserve service for less than its maximum expected use and simply pay unreserved use charges in the hours in which it exceeds that usage. We believe the unreserved penalty regime we articulate in this Final Rule will provide a reasonable incentive to ensure that transmission customers reserve the appropriate level of transmission service without unduly charging a transmission customer for inadvertent unreserved use. In addition, transmission customers will continue to be subject to civil penalties on a case-by-case basis, so attempts to game this penalty regime could result in additional penalties depending on the specific facts at issue. We reject the suggestion in some comments that the transmission provider should only assess unreserved use penalties where a transmission customer repeatedly uses transmission service that it has not reserved. Rather, we find that penalties are appropriate for all unreserved uses of the system. Because we are allowing penalties to be based on the period of unreserved use, not the reservation period, such penalties do not unduly charge a transmission customer for inadvertent unreserved use. This penalty regime will apply to all instances where a transmission customer has an unreserved use of transmission service, regardless of whether the transmission customer had an existing relevant transmission service reservation but for a lesser amount of service.

848. A transmission provider that wants to charge unreserved use penalties must explicitly state the penalty rate in its tariff. The Commission retains the current policy established in *Allegheny* that the unreserved use penalty rate may not be greater than twice the firm point-to-point rate for the period of unreserved use, as defined above.[523] We continue to believe that penalties up to twice the relevant firm point-to-point rate are just and reasonable, given the new definition for the penalty period. As a result, we establish a rebuttable presumption that unreserved use penalties no greater than twice the firm point-to-point rate for the penalty period defined above are just and reasonable. As we discuss above, the transmission customer must face a penalty in excess of the firm point-to-point transmission service charge it avoids through unreserved use of transmission service or the transmission customer will have no incentive to reserve the appropriate amount of service.

849. The Commission thus concludes that a penalty of twice the standard rate is not excessively punitive, particularly given the definition of the penalty period established in this Final Rule. Without evidence to the contrary, we

[519] *E.g.*, APPA, AWEA, TAPS, and TDU Systems.

[520] *E.g.*, APPA, AWEA, TAPS, and TDU Systems Reply.

[521] *E.g.*, NRECA, Nevada Companies, and Southern.

[522] There are a number of possible permutations of these principles. For instance, a transmission customer that has 25 MW of unreserved use in two hours on one day during the first week of the month and 50 MW of unreserved use in two hours on one day during the last week of the month will pay an unreserved use penalty based on the rate for 25 MW of daily firm point-to-point service and 50 MW of daily firm point-to-point service. A transmission customer that has 25 MW of unreserved use on two separate days during the first week of the month and 50 MW of unreserved use in two hours on one day during the last week of the month will pay an unreserved use penalty based on the rate for 25 MW of weekly firm point-to-point service and 50 MW of daily firm point-to-point service. A transmission customer that has 25 MW of unreserved use on two separate days during the first week of the month and 50 MW of unreserved use on two separate days during the last week of the month will pay an unreserved use penalty on 50 MWs of monthly firm point-to-point service.

[523] *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,545–46 (1997) (Allegheny).

believe an unreserved use penalty equal to twice the applicable rate should create the appropriate incentive to transmission customers to purchase the correct amount of transmission service. Nonetheless, we will allow transmission providers to make a filing under section 205 of the FPA to propose an unreserved use penalty in excess of twice the relevant firm point-to-point rate for pervasive unreserved use. Transmission providers that propose such a rate must establish that a higher penalty rate is required to combat pervasive unreserved use of transmission. In arguing for such a higher penalty rate, the transmission provider must address why the standard penalty rate that penalizes repeated unreserved use is not adequate to discourage repeated instances of unreserved use of transmission service.

b. Distribution of Operational Penalties

NOPR Proposal

850. In the NOPR, the Commission proposed to have the transmission provider distribute to non-offending, unaffiliated transmission customers operational penalties incurred by the transmission provider's merchant function or its affiliates.[524] For those transmission providers subject to operational penalties, the Commission proposed to require the transmission provider to make an annual compliance filing to notify the Commission of the amounts of such operational penalties incurred during the year and to propose a method to identify non-offending, unaffiliated transmission customers to which the transmission provider would distribute penalty amounts. In addition, the Commission also proposed to allow a transmission provider to avoid an annual compliance filing by making a one-time filing to propose a mechanism through which it would identify non-offending, unaffiliated transmission customers and a method by which it would distribute the operational penalties it or its affiliates have incurred to the identified transmission customers. Finally, the Commission proposed to prohibit transmission providers from recovering for ratemaking purposes or through any service or facility under the Commission's jurisdiction any cost it incurs when it or an affiliate pays an operational penalty.

Comments

851. Transmission customers along with several other commenters support the Commission's proposal to distribute operational penalties paid by the transmission provider's merchant function to non-offending, unaffiliated transmission customers.[525] Entegra and Morgan Stanley advocate extending the proposal so that the transmission provider distributes operational penalties paid by all transmission customers to non-offending unaffiliated transmission customers. Entegra also notes that the Commission's policy in the natural gas setting is that pipelines must credit all penalty revenues back to non-offending shippers. Entegra argues that the precedent the Commission cited in proposing that operational penalties paid by the transmission provider be distributed to non-offending, unaffiliated transmission customers applies equally to penalties paid by affiliated and unaffiliated transmission customers.[526]

852. With regard to unreserved use penalties, NRECA and TDU Systems argue that the Commission should encourage transmission providers to supervise inadvertent unreserved use and notify the customer of such occurrence rather than rely on large unreserved use penalties. They argue it is better to prevent unnecessary costs than to approve *post hoc* penalties for unintentional unreserved use that could have been prevented.

853. A number of transmission providers oppose the portion of the Commission's proposal that would prohibit their non-offending affiliates from receiving a portion of the operational penalties the transmission provider incurs.[527] For instance, PNM–TNMP asserts that the Commission should allow the transmission provider's non-offending affiliates, which are abiding by the same rules as other transmission customers in accordance with Standards of Conduct, to be eligible to receive a portion of the operational penalties the transmission provider incurs. In the specific case of unreserved use penalties, Southern does not support distributing penalties imposed on a transmission provider's affiliate to other OATT customers. Southern argues that such a proposal is predicated upon the false assumption that such penalties are not of true financial consequence. Southern asserts that penalties paid by an affiliate do, in fact, represent a real cost to the wholesale business of that affiliated entity. In its reply comments, TDU Systems disagrees with comments that suggest that non-offending affiliates should be allowed to receive a load ratio share of penalty revenues when a transmission provider or one of its affiliates incurs an operational penalty. TDU Systems argue that allowing any member of the corporate family to retain any portion of the penalty revenues incurred by another member of the corporate family will dilute the incentive inherent in the Commission's proposal.

854. Seattle suggests that compliance monitoring and enforcement to ensure that the transmission provider appropriately assesses penalties to its affiliates will be as important as correctly accounting for and distributing the revenues from penalties collected from affiliates.

855. Most commenters were supportive of the Commission's proposal to have transmission providers notify the Commission of the amounts of all operational penalties they incurred during the year through either an annual compliance filing or a one-time filing.[528] Several commenters expressed a preference for a one-time filing by transmission providers.[529] For instance, Ameren states that it prefers the use of a one-time filing to propose a mechanism through which the transmission provider would identify non-offending, unaffiliated transmission customers and a method by which the transmission provider would distribute the operational penalties it or its affiliates have incurred to the identified transmission customers. Ameren believes this would be less burdensome than an annual repeated compliance filing. TDU Systems, on the other hand, prefer the Commission's proposal to require an annual reporting of penalties levied and penalty revenues credited in order to foster greater transparency on this matter. TDU Systems believe greater transparency through improved reporting requirements would provide greater opportunities for detecting abuses by transmission providers or their affiliates, either in imposing inappropriate penalties on transmission customers or in failing to penalize their own or their affiliates' transgressions. In addition, TDU Systems suggest that this reporting requirement should include details on the amount of penalties

[524] An operational penalty explicitly defines the charge associated with a set of pre-defined activities (*e.g.*, unreserved use of transmission service, completing request studies outside of the 60-day due diligence deadline) that are not in compliance with specific provisions of the OATT.

[525] *E.g.,* APPA, ELCON, Entegra, TAPS, TDU Systems, Sacramento, and Seattle.

[526] Entegra cites *Carolina Power & Light Co. and Florida Power Corp.,* 103 FERC 61,209 at P 24 (2003) (*Carolina Power & Light*).

[527] *E.g.,* EEI, MidAmerican, Nevada Companies, and PNM–TNMP.

[528] *E.g.,* EEI, Suez Energy NA, Sacramento, TAPS, and Wisconsin Electric.

[529] *E.g.,* Ameren and PNM–TNMP.

levied, whether on customers or the transmission provider or its affiliates, for all violations. With regard to the annual reporting requirements (for those companies that do not propose a standard mechanism to handle the distribution of penalties), Nevada Companies suggest that a standard template be proposed so that all companies are following the same reporting format.

856. Several commenters make recommendations that they argue will ease the administrative burden of distributing operational penalties paid by the transmission provider to non-offending, unaffiliated transmission customers. MidAmerican suggests that excluding short-term firm and non-firm transactions from the distribution methodology would avoid the need to develop a costly and administratively difficult program. TVA suggests that the amount of any such operational penalties should simply be a credit against the transmission provider's transmission revenue requirement, thereby more efficiently reducing the cost of transmission service to transmission customers.

857. Several commenters argue that the transmission provider must be made whole before it distributes any penalty revenues. For instance, EEI supports the Commission's proposal to the extent penalty revenues exceed the cost of transmission service. Nevada Companies assert that it is the transmission provider's native load that incurs the cost of correcting for the offending customer's intentional deviation from schedule or for a transmission customer's self-provided reserves being unavailable. Therefore, Nevada Companies contend that any penalties should be returned to the native load to offset its cost of generation.

858. Sacramento and WPS Companies' reply comments support the Commission's proposal to prohibit a transmission provider from recovering any cost it incurs when it or an affiliate pays an operational penalty through jurisdictional rates or services.

Commission Determination

859. The Commission agrees with those commenters recommending that we broaden the NOPR proposal, which required transmission providers to distribute to non-offending, unaffiliated transmission customers only the unreserved use penalties the transmission provider's merchant function incurs. Consistent with our conclusion regarding imbalance penalties, we conclude that it would be more appropriate for transmission providers to be required to distribute all unreserved use penalties they collect, whether from the transmission provider's merchant function or other transmission customers. The penalties the transmission provider pays for late studies are penalties that, by their nature, are fully distributed only to non-affiliated transmission customers. Requiring the transmission provider to distribute the unreserved use penalty charges that its merchant function incurs will ensure that the transmission provider faces a meaningful financial consequence when its merchant function incurs an operational penalty. Extending the NOPR proposal to all unreserved use penalty revenues the transmission provider collects maintains the incentive structure of the unreserved use penalty and prevents the transmission provider from retaining revenues above those it should reasonably be allowed to earn.[530] This determination is consistent with the Final Rule for imbalance penalties and the Commission's decision in Order Nos. 637 and 637–A.[531]

860. We agree with those commenters that suggest that non-offending affiliates of the transmission provider, including the transmission provider's native load customers, should be eligible to receive a portion of the unreserved use penalties that the transmission provider collects. Unreserved use penalties are assessed against transmission customers and should, therefore, be distributed to all non-offending transmission customers, whether affiliated with the transmission provider or not. Given the distribution of unreserved penalties articulated above, the transmission provider's corporate profit is reduced if one of the transmission provider's wholly-owned marketing affiliates pays an operational penalty to the transmission provider. This is so because the corporate shareholders ultimately pay the marketing affiliate's penalty, while the transmission provider distributes the revenues to non-offending transmission customers.

861. The Commission requires the transmission provider to make an annual compliance filing and to propose in that filing a mechanism through which it will identify non-offending, transmission customers and a method by which it will distribute the unreserved use penalties revenue it receives to the identified transmission customers. This rule is consistent with our determination regarding the distribution of imbalance penalties. The transmission provider must also indicate in its compliance filing how it will distribute late study penalties to unaffiliated transmission customers. In addition, the transmission provider is required to make an annual filing with the Commission, described further below, that provides information regarding the penalty revenue the transmission provider has received and distributed. We will not allow the transmission provider to make an annual filing to propose a distribution method for unreserved use and late study penalties, as proposed in the NOPR. We agree with Ameren that restricting the transmission provider to proposing a distribution method through the transmission provider's compliance filing will reduce the administrative burden of distributing operational penalties. We believe that we can accomplish the goals underlying a mandatory annual filing to propose a distribution method—to detect inappropriate penalties and failure to penalize the transmission provider's affiliates—by requiring an annual informational filing. As suggested by Seattle, compliance monitoring and enforcement by Commission staff will provide a measure of assurance that the transmission provider appropriately assesses penalties.

862. All point-to-point and network transmission customers, including the transmission provider's native load, will be eligible to receive a portion of the penalty revenues distributed by the transmission provider. As a result, we will not adopt MidAmerican's proposal that we exclude short-term firm and non-firm transmission customers to reduce the burden to the transmission provider. Given the steps we have taken to manage the transmission provider's burden of distributing penalty revenues, we believe it more equitable to allow all transmission customers subject to operational penalties to be eligible to receive a portion of the distributed penalty revenues. In response to TVA's suggestion that the amount of any such operational penalties be credited against

[530] As we explain further below, the transmission provider will be allowed to retain the base firm point-to-point transmission service charge when it assesses an unreserved use penalty.

[531] *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services,* Order No. 637, 65 FR 10156 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,091 at 31,309 (2000) (''* * *to effectively shift pipelines to the use of the non-penalty mechanisms described above to solve and prevent operational problems, it will be necessary to eliminate the pipelines' financial incentive to impose penalties and OFOs. Thus, the Commission is requiring pipelines to credit the revenues from penalties and OFOs to shippers.''); *order on reh'g,* Order No. 637–A, 65 FR 35706 (Jun. 5, 2000), FERC Stats. & Regs. ¶ 31,099 at 31,609 (2000) (''The goal of the Commission's new policy on penalties is to encourage pipelines to rely less on penalties and more on non-penalty mechanisms to manage their systems* * *.'').

the transmission provider's transmission revenue requirement, we note that the transmission provider is free to propose this mechanism, with assurances that offending customers will not benefit, and we will decide the appropriateness of the proposal on a case-by-case basis.

863. We agree with those commenters that assert that the transmission provider must be made whole before it distributes any penalty revenues. With regard to unreserved use penalties, we will allow the transmission provider to retain the base firm point-to-point transmission service charge, but require it to distribute any revenue collected above the base firm point-to-point transmission service charge. For instance, if a transmission customer has unreserved use that results in a penalty equal to twice the rate for firm weekly point-to-point service, then the transmission provider can retain an amount equal to the rate for firm weekly point-to-point transmissions service. A transmission provider will be required to distribute the entire amount it pays for completing service request studies on an untimely basis.

864. We will not require transmission providers that make an annual compliance filing to use a standard template, as suggested by Nevada Companies. Transmission providers are in the best position to determine the least burdensome way to present the information required. We will provide guidance, however, on the information that transmission providers must provide in their annual informational filings. Transmission providers must provide: (1) A summary of penalty revenue credits by transmission customer, (2) total penalty revenues collected from affiliates, (3) total penalty revenues collected from non-affiliates, (4) a description of the costs incurred as a result of the offending behavior, and (5) a summary of the portion of the unreserved penalty revenue retained by the transmission provider.

865. Transmission providers are prohibited from recovering for ratemaking purposes or through any service under the Commission's jurisdiction any amount it or an affiliate pays as an operational penalty. This will ensure that the transmission provider faces a true financial consequence when it or an affiliate incurs an operational penalty.

c. Applicability of Operational Penalties Proposal to RTOs and Other Independent or Non-Profit Entities

866. The Commission did not address the degree to which RTOs and other independent entities would be subject to operational penalties in section V.C.4 (Operational Penalties) of the NOPR. For the most part, the discussion in that section of the final rule addressed how a transmission provider should distribute operational penalties it incurs when it takes transmission service under its own tariff. In the section V.D.5 (Acquisition of Transmission Service) of the NOPR, the Commission separately addressed whether RTOs should pay operational penalties for failure to complete request studies on a timely basis.

Comments

867. Several RTOs and RTO members asked that the Commission clarify that RTOs are not subject to any operational penalties.[532] Entergy opposes the Commission's proposal to assess operational penalties against non-RTO transmission providers, but not RTOs. However, if the Commission maintains this distinction, Entergy asks that it clarify that independent entities—such as Entergy's Independent Coordinator of Transmission—and the transmission providers that allow independent entities to process transmission service requests will have the same protection from operational penalties as RTOs. PGP argues that, in the case of non-profit transmission providers, requiring the transmission provider to pay ''non-offending'' customers when the provider incurs operational penalties is self-defeating, because there is no one other than the customers to bear the cost of the penalty. PGP cites Bonneville as an example and notes that Bonneville must recover all costs from its customers.

Commission Determination

868. This section of the Final Rule primarily addresses how transmission providers should distribute operational penalties they incur when taking transmission service under their own tariff. RTOs and independent transmission coordinators do not take transmission service, so most of the discussion in this section of the Final Rule is simply not applicable to either RTOs or independent transmission coordinators. RTOs and independent transmission coordinators are bound however by the requirement to distribute revenues they receive when they assess operational penalties. We address whether RTOs or independent transmission coordinators are subject to operational penalties due to processing transmission service request studies on an untimely basis in section V.C.5.a of this Final Rule. We address whether RTOs are subject to civil penalties in section 0 of this Final Rule.

869. We do not agree with those arguing that a non-profit transmission provider should be exempt from the requirement to distribute unreserved use penalties it pays when taking service under its own tariff. To the extent that a not-for-profit transmission provider incurs an operational penalty as a result of its activities as a transmission customer, it is still required to distribute penalties to non-offending customers. A non-profit transmission provider would only incur an operational penalty as the result of its wholesale marketing operations. As such, a non-profit transmission provider would pay for any operational penalty it incurs by using the profit it has earned through its wholesale marketing operations.

6. ''Higher of'' Pricing Policy

870. As noted in the NOPR, the Commission is concerned that some transmission providers may not be applying our existing pricing policies consistently and, as a result, customers may be quoted prices that are not consistent with the ''higher of'' policy.[533] The practice of quoting customers an incremental rate as a lump sum payment is inconsistent with our ratemaking policy and has the potential to discourage customers from proceeding with service requests.[534] Under the Commission's ''higher of'' pricing policy, when the requested transmission service requires network upgrades, the transmission provider should calculate a monthly incremental cost transmission rate using the revenue requirement associated with the required upgrades and compare this to the monthly embedded cost transmission rate, including the expansion costs.[535] This incremental rate should be established by amortizing the cost of the upgrades over the life of the contract.[536]

[532] *E.g.,* ISO New England, PJM, MISO, SPP, and Ameren.

[533] In Order No. 888, the Commission stated that system expansions should be priced at the higher of the embedded cost rate (including the expansion costs) or the incremental cost rate, consistent with the Transmission Pricing Policy Statement. *See Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act,* Policy Statement, 59 FR 55031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994), *order on reconsideration,* 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

[534] *Southwest Power Pool, Inc.,* 100 FERC ¶ 61,096 (2002) (designing a rate to include a balloon payment is not a substitute for a properly designed rate).

[535] *Southwest Power Pool, Inc.,* 112 FERC ¶ 61,319 at P 33 (2005).

[536] *See Southwest Power Pool, Inc.,* 98 FERC ¶ 61,256 at 62,026, *reh'g denied in pertinent part,*

NOPR Proposal

871. As a result of the Commission's concerns regarding application of the ''higher of'' pricing policy, the Commission sought comments in the NOPR on whether changes to the *pro forma* OATT are necessary to ensure that incremental cost transmission rates are presented as monthly rates for service.

Comments

872. Several commenters agree that incremental cost rates must be expressed as monthly rates, but do not believe that imposing this requirement requires changes to the *pro forma* OATT.[537] To ensure transparency, Bonneville recommends that transmission providers post on their OASIS the methodology used to calculate incremental rates. APPA suggests that the Commission simply state in the preamble to the Final Rule that the transmission provider must include a proposed incremental rate in its offer of service.

873. Other commenters see no need for clarification at this time. Southern states that it is not aware of problems regarding the calculation of incremental rates. Southern requests that the Commission consider allowing deviations to the Commission's ''higher of'' pricing policies and to allow all transmission providers, not just RTOs, to utilize participant funding. MidAmerican suggests the Commission defer consideration of possible changes to the *pro forma* OATT regarding this issue until the Commission undertakes comprehensive transmission pricing reform.

874. Other commenters support changes to the *pro forma* OATT that will ensure that incremental costs are presented as monthly rates for service.[538] EPSA suggests that the Final Rule include an example of an appropriate monthly revenue requirement calculation and the upgrade costs included in the monthly rate. Suez Energy NA supports this proposed change but requests that the transmission provider be required to provide in a clear format the existing transmission rate, the lump sum cost of the upgrades, and the incremental rate.

875. Some commenters ask the Commission to further clarify, or establish additional requirements, regarding incremental rates. Entegra states that the incremental rate should be stated as both a monthly unit rate and a lump sum representing the net present value of the upgrade costs with all inputs and assumptions in the calculation disclosed. Entegra further contends that the customer should be allowed to choose between paying the incremental rate, the lump sum, or some combination of the two (*e.g.*, to pay an incremental rate over some period of time and then to pay the balance of the upgrade costs as a lump sum). While Morgan Stanley supports the Commission's clarification that the transmission provider may not demand a lump sum payment as a condition of providing the requested service, it asks that transmission providers not be precluded from offering a lump sum payment option, or any other mutually agreeable approach, to customers.

876. MidAmerican, EEI and Allegheny recommend that the Commission clarify that the transmission provider is not currently limited to charging the customer the rate per MW-month specified in the facilities study for the entire term of service if the customer pays the incremental cost of the network upgrades. These commenters explain that the transmission provider's revenue requirement with respect to the incremental cost of network upgrades will vary over the customer's term of service in the same way as its embedded cost of service will vary, including the cost of capital, operations and maintenance expense and administrative and general expense. EEI argues that the transmission provider should have the same right to modify a rate based on incremental costs pursuant to section 205 that it has to modify embedded cost rates and that the transmission provider should be permitted to present an incremental cost rate as a formula rate.

877. Seattle states that incremental costs may require more rigorous treatment than simply stating a monthly rate, since the cost of expansion is very path specific and often the expansion will affect multiple beneficiaries. According to Seattle, the ''higher of'' pricing policy will often hinge on contestable assumptions regarding the beneficiaries of discrete expansion projects and the grey area that separates reliability related aspects of new transmission projects from projects intended to provide commercial benefits.

878. Great Northern requests that the Commission clarify that a transmission customer may adjust the term of its requested transmission service contract to provide a longer period for amortizing the cost of necessary system upgrades once the incremental cost of expansion is disclosed by the transmission provider, as the Commission seems to suggest in the NOPR.[539] In contrast, Allegheny states that the amortization period for the cost of an upgrade should not exceed the requested term of the contract, even if exercise of the rollover option by the customer is anticipated because transmission providers must have assurances of cost recovery for upgrades necessitated by customer decisions.

879. TAPS and EEI recommend that the Commission modify sections 19.3 and 19.4 of the *pro forma* OATT to specify that the transmission provider must present the incremental costs of transmission service on a $/MW month basis contemporaneous with providing the facilities study to the customer. TAPS further states that similar changes should be made to sections 32.3 and 32.4 of the *pro forma* OATT, to ensure that network customers are not scared off by inappropriate presentations of network upgrade costs. TAPS explains that, while more complex, it believes that ''higher of'' pricing can work in the context of network service if applied in a comparable manner to the transmission provider's treatment of the upgrades needed for service to its retail native load.[540]

880. ISO New England and PJM state that the Commission's pricing concerns are not present for their respective markets and, therefore, any rule promulgated in this proceeding should not apply to these RTOs.

881. TAPS argues that creditworthiness or security requirements associated with network upgrades for a transmission customer (in sections 19.4 and 32.4 of the *pro forma* OATT) must be distinguished from the incremental cost or pricing of the upgrade. Otherwise, the customer may mistake a demand for security for a request for upfront payment of the entire cost of the upgrade.

882. In reply comments, EEI states that it continues to support the Commission's proposed modification to the way in which the transmission

100 FERC ¶ 61,096 (2002) (''We agree with SPP that the amortization period for upgrade costs should match the contract period * * * As the customer is only obligated to take service for the term of the contract, it is reasonable that the costs only be amortized over the term of the contract.'').

[537] *E.g.,* APPA, Bonneville, and Public Power Council.

[538] *E.g.,* ELCON, Constellation, FirstEnergy, NorthWestern, PGP, TDU Systems.

[539] *See* NOPR at P 285 (''Presenting the incremental charge in the form of a monthly rate allows a customer seeking a lower rate to choose to request a longer transaction term.'').

[540] *Citing Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,085, P 57 (2004) (applying Order 2003 crediting mechanism to network customers).

provider presents information on the incremental cost of network upgrades and asserts that nothing in the initial comments justifies a change in the Commission's policies with respect to the pricing of transmission service. EEI states that changes in transmission pricing policy, such as NRECA's proposal to require rolled-in pricing for network customers and TAPS's proposal to exempt network customers from security for the payment of costs related to network upgrades, are outside the scope of this proceeding.

Commission Determination

883. In the NOPR, the Commission sought comments on the narrow issue of whether changes to the *pro forma* OATT are necessary to ensure that, consistent with our ''higher of'' policy, incremental cost transmission rates are presented as monthly rates for service. The Commission did not propose any changes to the underlying pricing policy. Commenters' proposals to change or clarify the Commission's transmission pricing policy are therefore outside the scope of this proceeding.[541] Other comments are directed toward the application of our ''higher of'' policy in individual cases. These include the comments of Seattle (on the need to accurately identify the beneficiaries of the network upgrades), TAPS (on the use of ''higher of'' pricing in the context of network service), and EPSA (asking the Commission to present an example calculation of costs and rates). We will not address those comments here because they involve issues that are largely fact-specific that are best addressed on a case-by-case basis.

884. Based on the remaining comments received, the Commission concludes that changes to the language of the *pro forma* OATT to address this matter are not needed at this time. We believe that the existing pricing policy provides sufficient information for transmission customers to make an informed decision regarding a request for service.[542] Transmission providers must continue to include a proposed monthly incremental rate with their offer of service whenever the transmission provider proposes to charge the customer an incremental rate, as well as cost support indicating the derivation of the rate calculation consistent with the cost support that the transmission provider would provide to the Commission in a section 205 rate filing. Because transmission providers are required to explain the calculation of their incremental rate, we conclude that the transmission provider need not post on its OASIS the calculation methodology, as recommended by Bonneville. Similarly, in response to TAPS's concern about security payments, the transmission provider's explanation should allow the customer to clearly distinguish between any security requirements associated with the service and the incremental cost of the service.

885. We will not adopt Great Northern's recommendation to require the transmission provider to permit the customer to opt for a longer contract term (to obtain a longer amortization period and a lower rate) once the incremental cost of the upgrades has been determined. The specific upgrades required to provide transmission service may depend on the time period over which the service is provided; therefore, allowing the customer to opt for a longer contract term may trigger a need for additional, or different, upgrades.

7. Other Ancillary Services

886. Other than the pricing of imbalances, the NOPR did not address pricing issues related to ancillary services required under the *pro forma* OATT. A few commenters nonetheless proposed revisions to the *pro forma* OATT regarding the pricing and procurement of, and other issues related to, ancillary services.

a. Demand Response

Comments

887. Alcoa submits that load resources (*i.e.*, demand response) should be permitted to self-supply and, under certain circumstances, sell ancillary services to third parties. Alcoa states that large customers such as aluminum smelters are capable of providing, for themselves and third parties, some ancillary services so long as they are not required to subrogate their aluminum business functions to the needs of the ancillary service markets. In Alcoa's view, demand resources such as Alcoa's smelter loads should be appropriately compensated as providers of ancillary services, recognizing their ability to contribute significantly to the operational flexibility of energy markets and the stability of the grid. Alcoa asserts that industrial loads' contribution to the reliability of the grid was demonstrated during the August 2003 Blackout, when Alcoa's smelters remained in operation and facilitated the restoration of the system. Accordingly, Alcoa asks the Commission to require transmission providers to recognize that demand response resources can be a substitute for ancillary services such as Energy Imbalance, Operating Reserve and Spinning Reserve.

Commission Determination

888. With respect to Alcoa's concern regarding a transmission customer's own use of ancillary service, we note that the existing *pro forma* OATT requires transmission providers to permit transmission customers to purchase ancillary services from third parties or make alternative comparable arrangements for the provision of all ancillary services except for scheduling, system control and dispatch service and reactive supply and voltage control service. Regarding the sale of other ancillary services including energy imbalance, operating reserve and spinning reserve by load resources, we agree that such sales should be permitted where appropriate on a comparable basis to service provided by generation resources. Comparable treatment of load resources is consistent with Staff's August 2006 Assessment of Demand Response & Advanced Metering Report[543] as well as provisions of EPAct 2005.[544] We note that some RTOs and ISOs already allow demand response resources to participate in certain ancillary services markets, while participation of such resources in other ancillary services markets is being studied. We therefore modify Schedules 2, 3, 4, 5, 6, and 9 of the *pro forma* OATT to indicate that Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Spinning Reserves, Supplemental Reserves and Generator Imbalance Services, respectively, may be provided by generating units as well

[541] Comments that fall into this category include those of Entegra, Suez Energy NA, Morgan Stanley, MidAmerican, EEI (regarding the right to modify incremental rates) and Allegheny.

[542] Because the Commission declines to adopt changes to the *pro forma* OATT regarding the ''higher of'' pricing policy, the requests of ISO New England and PJM to exempt ISOs and RTOs from tariff changes related to that policy are moot. Procedures regarding implementation of the Final Rule by ISOs and RTOs are otherwise discussed in section IV.C.

[543] In the Demand Response Report, staff recommended that federal and state regulators consider whether to allow appropriately designed demand response resources to provide all ancillary services including spinning reserve, regulation, and any new frequency responsive reserves. Demand Response Report at 97–100.

[544] Section 1252 (f) of EPAct 2005 states: ''It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.''

as other non-generation resources such as demand resources where appropriate.

b. Procurement and Pricing of Ancillary Services Generally

Comments

889. Steel Manufacturers Association contends that the *pro forma* OATT's approach to other generation-based ancillary services should recognize that regional ancillary services markets do a better job of ensuring system reliability and holding down ancillary services costs than ancillary services provided on a control area by control area basis. Steel Manufacturers Association cites to MISO and SPP reports that provide evidence that ancillary services provided across large geographical regions are more effective and economical than when those services are provided by single utilities. For example, Steel Manufacturers Association notes that the SPP report concluded that, if a single Area Control Error were used for SPP, energy used for regulation service could be reduced by approximately 30 percent. Steel Manufacturers Association contends that, although ancillary services markets in the organized markets have proven successful at ensuring reliability and at keeping ancillary services costs low and predictable, utilities outside of the RTO and ISO markets continue to provide ancillary services primarily from their own limited pools of generation resources.

890. Occidental and Steel Manufacturers Association propose that transmission providers should be required, if feasible, to competitively procure ancillary service products if there are suppliers of such services other than the vertically integrated merchant function. Occidental argues that such procurement will result in just and reasonable rates for these generation-related ancillary services that reflect their cost-effective market-based competitive supply. In Occidental's view, competitive procurement of ancillary services will also help assure non-discriminatory treatment of transmission customers since transmission providers will have less incentive to favor their merchant function in the provision of generation-related ancillary services. Occidental notes that such procurement should be conducted in a manner consistent with reliability.

891. Alcoa argues that the transmission provider's costs of providing ancillary services for the network as a whole should not be socialized on a MWh basis without regard to the relative cost burden that specific customers impose on the transmission system. Alcoa contends that, while a particular consumer may use a considerable quantity of energy, the cost of serving that customer beyond the per-unit energy cost may be much less than it would be for other individual customers or groups of customers.

Commission Determination

892. The Commission recognizes that there can be possible economic and reliability benefits to larger geographic markets for ancillary services, as suggested by Steel Manufacturers Association. However, as stated in the NOPR and repeated above the purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures or, as proposed here, to modify existing market structures. We do not believe that altering the scope of the current ancillary services markets is needed to remedy undue discrimination at this time.

893. Similarly, we conclude that a fundamental overhaul of the current procurement and pricing of ancillary services, as proposed by Occidental and Steel Manufacturers Association, is beyond the scope of this proceeding.[545] The *pro forma* OATT already permits transmission customers to make alternative arrangements to satisfy certain of their ancillary services obligations. Therefore, transmission customers are free to seek out competitive providers for those ancillary services other than scheduling, system control and dispatch service and reactive supply and voltage control service from third party suppliers. We also find Alcoa's contention that the transmission provider's costs of providing ancillary services for the network as a whole should not be socialized on a MWh basis without regard to the relative cost burden that specific customers impose on the transmission system, to be beyond the scope of this Final Rule.

c. Pricing and Procurement of Reactive Power

Comments

894. Several commenters[546] suggest that the Commission consider the need for reform of the methods of compensation for the provision of reactive power.

895. Alcoa argues that ancillary services pricing should recognize the efficiency contributions made by load as a result of their demand response capabilities and the contribution that load located near generators makes to the provision of reactive power in particular. Alcoa states that the localized supply of reactive power near load centers can alleviate transmission constraints and allow cheaper real power to be delivered into a load center, as the provision of such reactive power increases the available flow for real power between two points. Alcoa argues that the *pro forma* OATT should recognize and credit the manner in which certain loads' location and load profile allows for the provision of reactive power and contributes to real power transfer capability.

896. Occidental objects to the existing requirement that transmission customers purchase reactive power service from the transmission provider, arguing that numerous independent generators provide reactive supply and voltage control to support transmission service in competitive wholesale markets. Occidental states that the Commission should formalize the policy of compensating generators on a comparable, non-discriminatory basis for several ancillary services, particularly providing reactive power capability, by requiring changes to the *pro forma* OATT to mirror the changes accepted by the Commission to the PJM and MISO tariffs. Occidental contends that amending the *pro forma* OATT to formalize this policy would be consistent with the FPA and achieving non-discriminatory access to transmission. Occidental notes that PJM and MISO amended their tariffs to provide equal compensation to affiliated and non-affiliated generators based on the generation owner's monthly revenue requirement for reactive supply and voltage control as accepted by the Commission. Occidental also notes that, when addressing generator interconnection agreements in Order No. 2003–A, the Commission stated that ''if the Transmission Provider pays its own or its affiliated generators for reactive power within the established [power factor] range, it must also pay [the interconnecting, independent generator].'' [547]

897. SPP requests that the Commission reform its reactive power pricing methodology, which has grown

[545] We note, however, that the rates charged for these ancillary services must be just and reasonable under the Commissions standard of review. Thus, if less expensive options to supply ancillary services (including from demand side resources) are available, we would expect the transmission provider to examine such options.

[546] *E.g.*, SPP, Alcoa, and Occidental.

[547] *See* Order No. 2003–A at P 416.

out of *AEP Serv. Corp.*[548] SPP contends that the Commission can reduce uncertainty and litigation surrounding the pricing of reactive power by acting generically in a rulemaking rather than causing the industry to litigate reactive power pricing issues on a case-by-case basis. SPP argues that, based on its studies, it does not expect to call upon IPPs to provide reactive power; and therefore, it should not be required to pay for reactive power. SPP questions whether paying all IPPs a reservation charge, regardless of any determination of need or of the location of the plant and the locational need for reactive power, provides the appropriate siting incentives. SPP contends that the Commission can reduce the uncertainty and litigation by acting generically rather than causing the industry to fully litigate these issues in numerous cases before various courts. In addition, SPP challenges whether the AEP pricing method for reactive power continues to be appropriate. SPP suggests the Commission consider alternative pricing options, such as: Tying compensation to the actual provision of reactive power; eliminating compensation for the ninety-five percent leading/lagging band contained in most interconnection agreements, as such costs may be considered as a cost of interconnection and included in the power sales price; or, allowing compensation only outside of the band or perhaps when a sale is displaced.

Commission Determination

898. In Order No. 2003 *et al.*, the Commission found that interconnection customers must be treated comparably with the transmission provider and its affiliates in terms of reactive power compensation. The Commission required the transmission provider to pay interconnecting generators for providing reactive power within the specified range if the transmission provider so pays its own generators or those of its affiliates.[549] Commenters seeking reform of the methods of compensation for the provision of reactive power have not demonstrated that such reforms are needed at this time to remedy undue discrimination or that the current compensation method does not provide a comparable result. Accordingly, we do not believe that acting generically on pricing reactive power is needed at this time and we will continue to resolve compensation issues for reactive power to qualifying generators on a case-by-case basis based on the circumstances presented.

899. In response to SPP's specific proposals for the treatment of reactive power, we note that the Commission recently found that it is unduly discriminatory and non-comparable for SPP to apply a ''needs'' test to reactive power capability for independent power producers to receive compensation that is not also applied to all other generating plants in its vicinity.[550] The Commission also found that parties may make a separate FPA section 205 filing with the Commission with criteria, applied comparably and prospectively, that would determine which generators would receive reactive power compensation.

900. Finally, Alcoa's assertion that certain loads' location and load profile allows for the provision of reactive power to the transmission system is consistent with Staff's February 2005 report, Principles for Efficient and Reliable Reactive Power Supply and Consumption,[551] as well as the above-cited provisions of EPAct 2005. As previously discussed, we have modified Schedule 2 of the *pro forma* OATT to allow for the provision of Reactive Supply and Voltage Control from demand resources where appropriate.

D. Non-Rate Terms and Conditions

1. Modifications to Long-Term Firm Point-to-Point Service

a. Planning Redispatch and Conditional Firm Options

901. The current *pro forma* OATT requires the transmission provider to provide two types of redispatch service: Planning redispatch and reliability redispatch.[552] Planning redispatch is a product that Order No. 888 required transmission providers to use, in certain circumstances, to create additional transmission capacity to accommodate a request for firm transmission service. Specifically, the existing *pro forma* OATT requires the transmission provider to expand or upgrade its transmission system or, if it is more economical, plan to redispatch its resources to provide requested firm point-to-point service, provided redispatch does not (1) degrade or impair the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (2) interfere with the transmission provider's ability to meet prior firm contractual commitments to others.[553] The transmission provider must first identify planning redispatch options in the system impact study in conjunction with identifying relevant system constraints that impact the service request.[554] When a system impact study and facilities study identify planning redispatch as a more economical means of relieving a transmission constraint than a transmission upgrade, the customer is obligated to pay the costs of redispatch consistent with Commission policy.

902. Reliability redispatch is required, when feasible, to relieve system constraints that would otherwise cause curtailment of the network customer or transmission provider loads. To provide reliability redispatch, the transmission provider redispatches all network resources and transmission provider resources on a least-cost basis. The transmission provider and network customers each pay a load ratio share of these redispatch costs.[555]

NOPR Proposal

903. In the NOPR, the Commission stated its belief that current practices for evaluating long-term firm point-to-point service may not be comparable to the manner in which transmission service is planned for bundled retail native load and may no longer be just, reasonable and not unduly discriminatory. The Commission described two potential solutions: modifications to the planning redispatch provisions and conditional firm point-to-point service.[556] The Commission proposed to modify the existing planning redispatch option by (1) accelerating the study of planning

[548] Opinion No. 440, 88 FERC ¶ 61,141 (1999).

[549] *See* Order No. 2003–B at P 119.

[550] *See Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 (2006).

[551] *See* Staff Report: Principles of Efficient and Reliable Reactive Power Supply and Consumption (Docket No. AD05–1–000), available at *http://www.ferc.gov/EventCalendar/Files/20050310144430–02–04–05-reactive-power.pdf.* Staff noted that in many cases load response and load-side investment could reduce the need for reactive power capability in the system and that increasing reactive power at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket. *See id.* at 4, 108. The report also noted that distributed generators have the same reactive power characteristics as large generators, with both producing dynamic reactive power, and that the amount of reactive power does not necessarily decrease when voltage decreases. *Id.* at 27.

[552] In Order No. 888, the Commission referred to planning redispatch as economic redispatch. Here we avoid the term economic redispatch because in the last ten years it has taken a different meaning in the industry and because we will no longer require that planning redispatch be capped at the cost of expansion.

[553] *See pro forma* OATT section 13.5.

[554] *See pro forma* OATT section 19.3.

[555] *See pro forma* OATT sections 33.2–33.3.

[556] Conditional firm point-to-point service (hereinafter conditional firm service) and planning redispatch point-to-point service (hereinafter planning redispatch service) are options available under long-term firm point-to-point service.

redispatch in the transmission request study process, (2) requiring an estimate of the number of hours of redispatch that may be required to accommodate the requested service, (3) requiring a preliminary estimate of the cost of planning redispatch, and (4) pricing planning redispatch services to facilitate increased availability of the service.[557] The Commission suggested that conditional firm service could also be used to accommodate additional transactions, defining the service as a form of firm point-to-point service that includes less-than-firm service in a defined number of hours of the year when firm point-to-point service is unavailable. The Commission sought comment on its preliminary view that planning redispatch is the superior option because, in part, it is comparable to the way the transmission provider plans for bundled retail native load.

904. The Commission's October 12 Technical Conference focused, among other things, on issues related to the planning redispatch and conditional firm proposals in the NOPR. On November 15, 2006, the Commission issued a notice (November 15 Notice) requesting supplemental comments on a transparent redispatch proposal submitted by Transparent Dispatch Advocates (TDA proposal) and certain aspects of the conditional firm option.[558] The Commission also requested comments regarding the conditional firm option, including whether it is a complementary service to planning redispatch, whether it should be available for all long-term requests or limited to a request where the customer agrees to pay for upgrades, potential modeling problems, and requirements for defining the conditions under which the service would be curtailable.[559]

Comments

905. Some commenters agree with the Commission's preference for modifications to planning redispatch over development of conditional firm service.[560] They state that the attributes of conditional firm service are not clearly defined and key implementation issues are unresolved. They state that using planning redispatch to the maximum degree feasible, while not interfering with reliability, is inherent in maximizing the efficient use of the transmission system and should be fully evaluated before undertaking expensive expansion of the transmission system. Other commenters state that conditional firm service will create significant complications for transmission providers and disincentives to build transmission in exchange for limited and questionable benefits for new point-to-point customers or LSEs.[561] EEI, Indianapolis Power and Ameren express doubt that customers would agree to be curtailed during peak usage periods. In response, AWEA contends that existing resources serving load would be able to manage curtailment risks so long as they could reasonably predict the curtailed hours.

906. Most independent power producers and a few other entities support the inclusion of both services in the *pro forma* OATT, stating that the services are required to remedy undue discrimination and provide for comparable transmission service.[562] Western Governors believe that the planning redispatch and conditional firm options are important to fully use the existing transmission grid and to enable new intermittent generation resources to reach markets. To build the case for transmission expansion, the Western Governors argue, it is important to demonstrate that the existing grid is being effectively utilized; approval of both options will help make this necessary demonstration. EPSA and AWEA state that, while they believe transmission providers should be required to offer both services, conditional firm service may be simpler and less costly to implement because it involves the transmission provider directing the customer to turn off its resources during a contingency. Similarly, Bonneville suggests that conditional firm service is a reasonable alternative to planning redispatch where a transmission provider cannot provide both options. Commenters state that the Commission should require transmission providers to offer conditional firm service and planning redispatch and allow customers to choose the option that best suits the physical, commercial and economic circumstances of the request.[563]

907. On the other hand, many commenters argue that the Commission should not require either option because the services are unnecessary, operationally unworkable, and legally unjustified, or because they would harm reliability and the quality of existing network service and provide disincentives for transmission investment.[564] Several commenters state that these services would make curtailments of existing firm service more likely and limit opportunities for use of secondary network service, thereby harming native load protections and reducing reliability, contrary to FPA sections 215 and 217 respectively.[565] Others opposing both options put forth primarily reliability, cost causation and comparability arguments. For example, Duke states that the two options are antithetical to reliable grid operation because they would require a transmission provider to grant a long-term request with the prior knowledge that it cannot be accommodated. International Transmission states that the grid is already operating at capacity and that requiring the transmission provider to accommodate additional megawatt-hours of service during periods of system stress would increase the likelihood of system failure. While it recognizes that conditional firm service has been successful in parts of the Western Interconnection, NRECA contends a mandate would undermine responsible planning and expansion of the transmission grid by harnessing the transmission provider's planning and dispatch functions to frame more and more elaborate service conditions for conditional firm service. APPA, Southern and Progress Energy argue that both services may require adoption of a form of organized LMP market, an action that raises significant political opposition and would be contrary to the Commission's commitment in the NOPR to avoid such restructuring. Similarly, other commenters contend that the planning redispatch option is only appropriate for transmission providers who are members of an RTO, ISO or

[557] The Commission did not propose to modify the reliability redispatch provisions that exist in the network integration transmission sections of the *pro forma* OATT.

[558] The following summary reflects comments received as initial and reply comments to the NOPR, as well as supplemental comments received in response to the November 15 Notice. Some commenters have changed their positions over time and these summaries reflect the most recent position expressed by commenters.

[559] Questions relating to the TDA proposal are discussed later in this section.

[560] *E.g.*, Exelon, FirstEnergy, ELCON, MidAmerican, Arkansas Commission, MISO, and East Texas Cooperatives.

[561] *E.g.*, EEI, Indianapolis Power, Ameren, and Northwest IOUs.

[562] *E.g.*, EPSA, AWEA, Entegra, BP Energy, Newmont Mining, Sempra Global, Suez Energy NA, PPM, Utah Municipals, Williams, Morgan Stanley, PPL, Project for Sustainable FERC Energy Policy, California Commission, CREPC, TranServ, South Carolina E&G, Constellation, Barrick Supplemental, Xcel Supplemental, and Bonneville Supplemental.

[563] *E.g.*, California Commission Supplemental, Williams Supplemental, Constellation Supplemental, and Barrick Supplemental.

[564] *E.g.*, Ameren, Duke, Entergy, Imperial, International Transmission, LPPC, Progress Energy, Santee Cooper, Salt River, Southern, Tacoma, TDU Systems, Community Power Alliance, Northwest IOUs, NorthWestern, NPPD, NRECA, Public Power Council, TVA, SPP Reply, South Carolina E&G Supplemental, E.ON Supplemental, MISO Supplemental, and APPA Supplemental.

[565] *E.g.*, Duke, EEI, LPPC, NRECA, NPPD, Progress Energy, Southern, Utah Municipals Reply, and Duke Reply.

who have an independent administrator of their transmission system.[566] Some of the commenters that urge rejection of both options state that a properly structured conditional firm service is preferable to the modified planning redispatch service should the Commission implement one of the services.[567]

908. Several commenters prefer the development of conditional firm service over the modifications to the planning redispatch service because of the complexities surrounding redispatch costs and protocols.[568] For example, in supplemental comments, EEI and Community Power Alliance state that, while not ideal, conditional firm service would provide an opportunity to meet customers' transmission needs and is preferable to Transparent Dispatch Advocates' redispatch proposal.[569] They also contend that the conditional firm option would provide faster provision of service and relative certainty of timing and costs for a new customer and its lenders, while ensuring reliability and promoting infrastructure expansion, so long as transmission providers are permitted to work with their customers to devise appropriate service parameters. Entergy believes conditional firm service can provide benefits to transmission customers without unfairly socializing costs to native load and network customers of the transmission provider. Overall, a majority of commenters express support for some form of conditional firm service.[570]

909. Several commenters argue that, if the services are required, the Commission should add to the services the following requirements: The services should not adversely affect reliability and service to firm customers or provide unduly preferential service to point-to-point customers; the services should be an interim option until transmission upgrades are in place to provide firm service; and, planning redispatch and conditional firm customers should bear the actual costs of the services received, including costs associated with system operational changes needed to accommodate the services.[571]

910. A few commenters believe that the Commission should allow for regional differences in development of the new services.[572]

Commission Determination

911. The Commission has determined that modifications to the current planning redispatch requirement and creation of a conditional firm option are both necessary for provision of reliable and non-discriminatory point-to-point transmission service. The planning redispatch and conditional firm options represent different ways of addressing similar problems. They can be used to remedy a system condition that occurs infrequently and prevents the granting of a long-term firm point-to-point service. These options also can be used to provide service until transmission upgrades are completed to provide fully firm service. Planning redispatch involves an *ex ante* determination of whether out-of-merit order generation resources can be used to maintain firm service. Conditional firm involves an *ex ante* determination of whether there are limited conditions or hours under which firm service can be curtailed to allow firm service to be provided in all other conditions or hours. As we explain below, both techniques are currently used under certain conditions by transmission providers to serve native load and, hence, it is necessary to make comparable services available to transmission customers in order to avoid undue discrimination.

912. We therefore find these options are complementary services that can remedy undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. There is support in the comments for development of some type of conditional firm service that would allow for a longer-term use of the grid when transmission is projected to be unavailable for a small portion of the year. Additionally, we note that both options could help integrate new generation more quickly. For example, when there is a lag between the time that a new generation resource becomes operational and the time that transmission upgrades can be built to accommodate the resource, these options allow power to reach customer loads at an earlier date. This can be particularly beneficial to renewable resources, such as wind, that can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run.

913. We recognize, however, that both options raise reliability concerns. The proposal in the NOPR for planning redispatch service would require the transmission provider to predict system conditions for the term of the service request, a task that becomes more difficult, and hence less accurate, with longer-term requests. This poses several related problems. Because longer-term forecasts are inherently uncertain and the further into the future the forecasts, the less accurate they are, the provision of planning redispatch service can threaten the reliability of service to native load unless very conservative assumptions are used. This incentive to use conservative assumptions to protect native load, in turn, increases the likelihood that planning redispatch service will be denied. This, in turn, will increase the number of disputes as to whether the denials were discriminatory. Such disputes would pose enforcement problems because they will turn on long-term projections regarding load growth, generation resource additions, *etc.,* that by definition involve some degree of subjectivity. Moreover, as we discuss below, there is evidence suggesting that, while transmission providers use planning redispatch to serve native load, they do not use it as a long-term tool to avoid future upgrades indefinitely.

914. In balancing the foregoing considerations, the Commission will modify the approach proposed in the NOPR in two principal respects. First, given the ability of both services to address similar problems, we have reconsidered the proposal that only one of the options should be required. We find that availability of both planning redispatch and conditional firm in the short-run is necessary to ensure that competitive power suppliers have comparable access to the grid. As discussed below, we will continue to require that transmission providers offer to provide planning redispatch under certain circumstances in which the transmission providers determine that there is insufficient ATC. If customers

[566] *E.g.*, CREPC, TVA, and East Texas Cooperatives.

[567] *E.g.*, EEI, Entergy, Ameren, Progress Energy, Santee Cooper, TAPS, E.ON Supplemental, TDU Systems Supplemental, LPPC Supplemental, Tacoma Supplemental, and PNM–TNMP Supplemental.

[568] *E.g.*, Manitoba Hydro, Nevada Companies, Sacramento, Pinnacle, East Texas Cooperatives, Barrick Reply, APPA Supplemental, Community Power Alliance Supplemental, Entergy Supplemental, and TAPS Supplemental.

[569] Section V.D.1.b contains a summary and in-depth discussion of the TDA proposal.

[570] The following entities expressed some level of support for conditional firm service: EPSA, AWEA, Entegra, BP Energy, Newmont Mining, Sempra Global, Suez Energy NA, PPM, Utah Municipals, Williams, Morgan Stanley, PPL, Project for Sustainable FERC Energy Policy, California Commission, Western Governors, CREPC, TranServ, Constellation, Manitoba Hydro, Nevada Companies, Sacramento, Pinnacle, PNM–TNMP, Bonneville, EEI, Entergy, Ameren, Progress Energy, Southern, Santee Cooper, Seattle, LPPC, Salt River, and TAPS.

[571] *E.g.*, EEI, Southern, TAPS, Seattle, APPA, LPPC Supplemental, Tacoma Supplemental and E.ON Supplemental. Issues related to pricing of planning redispatch service are addressed in paragraphs V.D.1.a.3.c below.

[572] *E.g.*, California Commission, PGP, Pinnacle, and Imperial.

request study of planning redispatch, transmission providers have an obligation to seriously evaluate the provision of planning redispatch from their own resources and provide customers with information on the capabilities of other generators to provide planning redispatch. If planning redispatch is unavailable from the transmission provider's resources or inadequate to meet customers' needs, transmission providers have an independent obligation to offer conditional firm, if available, as part of the firm point-to-point service.[573] Customers will have the choice of whether to request study of the planning redispatch option, the conditional firm option or both.

915. Second, we will not impose a planning redispatch or conditional firm obligation over the long run. Such an obligation is not, as described below, necessary to remedy undue discrimination and would otherwise pose reliability problems, put the transmission provider at risk for estimating the costs of long-term redispatch, and undermine incentives to upgrade the transmission grid. Therefore, we will limit the availability of both service options so that their duration is for a time period over which service can be reasonably provided without impairing reliability.[574] This limitation scales back the existing planning redispatch requirement in section 13.5 of the *pro forma* OATT that could, in practice, allow for an open-ended obligation to provide planning redispatch in lieu of upgrading the transmission system (*e.g.*, involving forecasts up to 30 years).

916. We discuss in detail the comparability and reliability findings that support these decisions below.

(1) Comparability

NOPR Proposal

917. In the NOPR, the Commission expressed its preliminary view that current practices for evaluating long-term firm point-to-point service may not be comparable to the manner in which transmission service is planned for bundled retail native load and may no longer be just, reasonable and not unduly discriminatory.[575]

Comments

918. Some commenters challenge the Commission's authority to order planning redispatch or conditional firm service as a remedy for potential undue discrimination. EEI and others argue that planning redispatch is not necessary to eliminate actual or perceived undue discrimination because many transmission providers do not rely on redispatch in planning to serve native load.[576] However, EEI also states that when transmission providers do incorporate redispatch into their system planning, they do so generally only when the cost of redispatch is lower than the cost of network upgrades and system reliability is not impacted. Some transmission providers state that they do not currently use planning redispatch in lieu of transmission construction in order to designate their network resources.[577] On the other hand, Entergy and Southern state that they currently use or have used planning redispatch of their own resources on the same basis that they allow any network customer to redispatch from the network customer's resources. For example, Southern states that it has used the redispatch potential of its generators during off-peak/shoulder periods on an interim basis until completion of transmission upgrades to designate network resources that otherwise might be undeliverable.[578] Entergy disagrees that there is undue discrimination because this service is not available to point-to-point customers, stating that network and point-to-point service are not similarly situated services. TDU Systems state that conditional firm service does not ensure comparability among types of transmission service or between transmission providers and transmission customers. NRECA and others argue that the Commission requires a better understanding of the degree to which comparability is a problem in providing point-to-point service before the Commission makes changes to point-to-point service.[579] In supplemental comments, EEI contends that the record in this proceeding does not demonstrate that conditional firm service is necessary to remedy undue discrimination.

919. Others assert that it is not within the Commission's jurisdiction to order planning redispatch for point-to-point customers because this type of redispatch requires use of the transmission provider's generation resources.[580] LPPC states that the comparability principle is wrongly applied to the use of generation by a transmission provider. In Salt River's view, the Commission proposal sets up its own form of discrimination by making redispatch of the transmission provider's resources mandatory while making redispatch of generation using firm point-to-point reservations and generation in other control areas voluntary.

920. Those that support development of both services support the Commission's statement in the NOPR that ''transmission owners may evaluate transmission availability to serve long-term transmission service requests in a manner that is not comparable with the method they use to evaluate transmission needs for bundled retail native load.'' [581] They argue that this divergent treatment of internal transmission needs versus external transmission requests is unduly discriminatory and violates the FPA. EPSA states that the fact that point-to-point service requests can be rejected due to a few hours of predicted reliability problems in a year is ''evidence of a poor use of existing transmission capacity and display clear discrimination against non-affiliated generation and its customers.'' [582] TransAlta states that its actual experience with planning redispatch in the Pacific Northwest demonstrates that planning redispatch is used discriminatorily to the benefit of some customers and the detriment of others.

921. In support of conditional firm service, Manitoba Hydro and Tacoma reiterate their experience that long-term transmission service requests are being denied due to constraints occurring during a small percentage of the time within the requested period of service.

[573] Application of planning redispatch and conditional firm service obligations to RTO and ISO transmission providers is discussed in section V.D.1.a.3.B.i below.

[574] As explained in more detail below, we adopt limitations that are tailored to the two types of customers that may request the options. First, for customers that agree to support the construction of new transmission facilities, redispatch and conditional firm point-to-point service will be available as a bridge until such time as those facilities are constructed and the relevant conditions must be specified in the initial service agreement and are not subject to change. Second, for customers that do not agree to support the construction of new facilities, the transmission provider will be able to re-evaluate the conditions under which services are provided every two years.

[575] The Commission did not propose to modify the reliability redispatch provisions that exist in the network integration transmission sections of the *pro forma* OATT.

[576] *E.g.*, EEI, TDU Systems, NRECA, Southern, and Duke Reply.

[577] *E.g.*, Southern, Duke, and Progress. Duke suggests that the Commission exempt transmission providers from the obligation to provide redispatch if they commit not to use redispatch as a planning tool for native load, network customers or merchant functions.

[578] Southern states that it offered this service on a comparable basis to a non-affiliated transmission customer.

[579] *E.g.*, TDU Systems and EEI Reply.

[580] *E.g.*, LPPC, NPPD, Progress Energy, and Salt River.

[581] *E.g.*, AWEA, Utah Municipals, Project for Sustainable FERC Energy Policy, EPSA, and Barrick Reply *citing* NOPR at P 300.

[582] EPSA Reply.

EPSA and AWEA similarly state that a transmission provider will reject a long-term firm service request unless it can satisfy every element of the request. Manitoba Hydro and others state that, in an era of transmission under-investment, optimizing the capacity usage is paramount to system reliability.[583] EPSA and AWEA further explain that the concept of turning off a generator to avoid system upgrades is not new; Maine Independence Station avoided expensive system upgrades by installing automatic switching devices to take it offline during certain system conditions. Seattle states that, according to the Seams Steering Committee of the Western Interconnection, utilization on most constrained paths is limited to only a few hundred hours per year and, therefore, it is highly likely that service under a conditional firm product could be offered for even a baseload plant without significantly impacting the capacity factor. Santee Cooper states that, unlike the planning redispatch option, conditional firm service is presumptively within the subject matter jurisdiction of the Commission.

922. Entergy states that the most comparable service for long-term point-to-point transmission customers is not a requirement that a transmission provider redispatch its own or network customers' resources to grant long-term firm point-to-point transmission service. The most comparable service instead is a service that allows the transmission provider to curtail the service granted, while permitting the point-to-point customer to obtain alternative, deliverable resources if and when such curtailments occur in real-time.

Commission Determination

923. We reject arguments that planning redispatch service is unnecessary to remedy undue discrimination as a collateral attack on Order No. 888. The obligation to provide planning redispatch was established in Order No. 888. The modifications proposed in the NOPR did not increase the obligation placed on transmission providers to use their generation resources to provide planning redispatch to point-to-point customers. Rather, the proposed modifications merely added specificity to the redispatch information already required in a system impact study and adjusted the timing of when the transmission provider must study planning redispatch options.[584] Therefore, many of the arguments raised, including arguments pertaining to the Commission's jurisdiction over transmission provider generation resources, are impermissible collateral attacks on the current planning redispatch obligation in Order No. 888. Entergy's argument that planning redispatch should not be available to point-to-point customers because they are not similarly situated to be able to provide redispatch from their own units thus ignores the current obligation for each transmission provider to provide redispatch from the transmission provider's resources, if available, in evaluating a request for long-term point-to-point service.[585]

924. Additionally, information in the comments counters the assertion that transmission providers do not use planning redispatch or service analogous to the conditional firm option for their own loads. Entergy and Southern volunteer that they have planned for redispatch of their own resources in order to designate network resources when ATC was unavailable.[586] As a caveat, Southern states that it has planned for the use of redispatch only for an interim period until upgrades could be constructed to make the transmission service from the designated resource fully firm. Entergy states that it offers planning redispatch service to network customers that plan to use their own resources to provide redispatch in real time. Contrary to EEI's assertion about the record in this proceeding, commenters, such as EPSA and AWEA, explain that some transmission providers already employ automatic devices, such as special protection systems (SPS), to take resources offline during certain system conditions. In a way that is analogous to the proposed conditional firm service, these protection schemes are used to increase native loads' firm uses of the transmission system until a contingency occurs that reduces available transmission.[587] This information, taken together, provides ample evidence to support our finding that transmission providers currently evaluate transmission availability to serve long-term firm point-to-point transmission service requests in a manner that is not comparable with the method they use to evaluate their own transmission needs and to integrate their resources to serve bundled retail native load.

925. Furthermore, we wish to emphasize that, in making these findings in support of a conditional firm option, we are not relying on the findings to create a new service. This Final Rule retains the two services adopted in Order No. 888—point-to-point service and network service. Conditional firm service is not a third service, but rather represents a modification to the existing procedures for granting long-term point-to-point service and the curtailment priorities for that service. The primary purpose of conditional firm is to address the ''all or nothing'' problem associated with the current procedures for requesting long-term point-to-point service. Currently, a request can be denied because firm service is unavailable in a very few hours of the year. For a customer who needs long-term point-to-point service to support a long-term transaction, this leaves the customer in the position of trying to cobble together a collection of shorter-term requests to effectuate its transaction, *e.g.*, arranging firm service in the periods when it is available and non-firm service in the other periods. Such a customer also risks interruption of the non-firm portion of its service for economic reasons, *e.g.*, a day of non-firm service for the customer combining firm and non-firm service could be interrupted for another customer seeking one month of non-firm service. We do not believe such an approach is just and reasonable. It makes little sense to ask the customer to cobble together a collection of firm and non-firm requests when the transmission provider has better information about when the service may be available or unavailable. It is therefore appropriate to require the transmission provider to grant the service on a conditional basis, as we explain further below.

926. We are however modifying the planning redispatch obligation, and similarly limiting the conditional firm option, to better reflect the manner in which redispatch or special protections schemes are used by transmission providers, in recognition of certain legitimate reliability concerns and the inherent difficulty of long-term projections in this area. This Final Rule limits transmission providers' planning redispatch obligations by removing the current obligation to provide planning redispatch for an indefinite period as

[583] *E.g.*, EPSA, AWEA, and Project for Sustainable FERC Energy Policy.

[584] *See pro forma* OATT section 19.3.

[585] *See pro forma* OATT section 13.5.

[586] Entergy and Southern. EEI's comments also indicate that at least a few transmission providers do rely on redispatch in planning to serve their native loads.

[587] SPS, also known as remedial action schemes, are used to varying degrees in every NERC reliability region. For example, there are about 65 SPS in the Western Interconnection. *See Western Electricity Coordinating Council Operating Procedures*, Index, V–1 to V–5 (revised July 2, 2002). There are 8 SPS used by Florida Power and Light in FRCC. *See Florida Power and Light Control Area Readiness Audit Report*, 19 (March 10–11, 2004). Two SPS are used in the Southern Subregion of SERC. *Reliability Coordinator Readiness Audit Report Southern Subregion Reliability Coordinator*, 19 (March 27–30, 2006).

long as the redispatch is cheaper than the relevant transmission upgrades. We also limit the conditional firm option by linking it to the transmission upgrades or a biennial assessment of the conditions.

927. We find such an open-ended obligation to provide this service is not necessary to remedy undue discrimination, nor is it consistent with the need to maintain system reliability. As indicated above, transmission providers temporally limit their use of planning redispatch and curtailment of resources and there is no evidence that transmission providers use these options on a prolonged basis, *e.g.*, for more than a few years, without upgrading their transmission systems. Rather, over the long run, transmission providers generally will construct sufficient transmission to integrate their resources on a firm basis. This is consistent with transmission planning requirements and the emphasis placed upon transmission expansion in this Final Rule. The modifications to long-term point-to-point service we adopt are consistent and comparable to the existing use of these options by transmission providers' bundled retail native loads. Thus, the planning redispatch and conditional firm options will be available primarily as interim measures until transmission systems are upgraded to meet the transmission service request. We believe this limitation will have the added benefit of lessening disincentives to provide the service so that more planning redispatch is offered to transmission customers by transmission providers.

928. We disagree with TDU Systems' statement that conditional firm service does not ensure comparability among types of transmission service or between transmission providers and transmission customers. TDU Systems' assertion is unsupported by any explanation or examples of how the conditional firm service would degrade comparability. Nevertheless, we believe the argument is essentially a collateral attack on Order No. 888. Order No. 888, not this rulemaking, created the distinction between point-to-point transmission service and network integration service. We did so to recognize the different ways in which transmission providers typically use their system. The two services are not precisely the same, nor were they intend to be identical. Nothing in this Final Rule changes these distinctions. Indeed, we are not changing the relative priorities applicable to firm point-to-point service, network integration service and service to bundled native load.[588] These services do, and will continue to, share the same priority—the highest priority of firm service on the transmission provider's system. The only change, as it relates to the conditional firm option, is to allow the customer to elect to have its long-term firm transmission service interrupted under certain defined circumstances. This does not harm other firm customers. Indeed, it has precisely the opposite effect: it permits an interruption to maintain firm service to other customers. Moreover, we find, as indicated above, that conditional firm service is necessary to remedy undue discrimination.

929. The addition of conditional firm service therefore does not significantly alter the existing balance between the point-to-point and network service. Customers of network service retain flexibility that is not enjoyed by point-to-point customers. Moreover, conditional firm does not reduce the availability of secondary network service or the ability of network customers to temporarily undesignate network resources any more than short-term firm point-to-point service already reduces the availability of these network customer options. We therefore reject TDU Systems' arguments and find that the addition of conditional firm service is necessary to remedy undue discrimination and will otherwise increase utilization of the grid without impairing system reliability.

(2) Reliability

(A) Ability to Predict Redispatch Opportunities and System Conditions in the Long Run

Comments

930. Some commenters state that redispatch, used as a planning tool rather than as a short-term operational tool, is overly complex, prone to causing disputes, reduces reliability and thus should not be included in the *pro forma* OATT.[589] Southern asserts that planning redispatch should not be required where it reduces reliability by reducing a utility's reserve margin, shifting the operational, reliability and economic risks from the new customer to native load, or causing a single contingency to overload the system. Additionally, Xcel states that pledging a network resource to support planning redispatch carries a risk of penalties for inadequate resources in some areas. MISO states that contingency conditions must be considered and respected when evaluating planning redispatch options so that there is no reliance on curtailment of service. MidAmerican and Progress Energy conclude that the customer must accept the risk of selecting planning redispatch service over transmission construction.

931. Several commenters request modification of the existing planning redispatch provisions of the *pro forma* OATT.[590] They state that the Commission should clarify that the current section 13.5 does not require planning redispatch when it would adversely affect system reliability or service to native load, network customers and other firm point-to-point customers or impair other contractual obligations. Indianapolis Power states that the Commission should modify section 13.5 to require all reasonable redispatch options be examined by the transmission provider.

932. In its reply comments, Southern explains that transmission providers fail to provide the currently required planning redispatch service to point-to-point customers because the service is impractical and would harm reliability. Southern contends that a redispatch scenario identified in a transmission plan may not be available in real time due to outages or loop flow. Southern is also concerned about the complications in planning and modeling that would occur if the transmission provider is required to redispatch multiple resources in order to accommodate multiple planning redispatch customers.

933. Similar to their arguments in favor of conditional firm, EPSA and AWEA state that planning redispatch is necessary because a transmission provider will reject a long-term firm service request unless it can satisfy every element of the request, even if reliability violations occur in only a few hours of the year. In its reply comments, EEI responds that there is no evidence to support the assertion that a transmission provider will reject a long-term firm service request unless it can meet every element of that request. EEI states that in such a situation the transmission provider must offer partial service, offer to perform a system impact study, and exercise due diligence in constructing needed upgrades to accommodate the request. EEI adds that the potential customer can also request short-term service. Finally, EEI states that there is no evidence that transmission providers are refusing to redispatch in response to customer request when redispatching resources would have no impact on reliability. In

[588] *See supra* section V.D.5.b.

[589] *E.g.*, Duke, Entergy, WAPA, NRECA, NPPD, LPPC, and Southern.

[590] *E.g.*, EEI, Indianapolis Power, Public Power Council, Southern, Seattle, Sacramento, and LPPC.

its reply comments, MISO states that denial of service complained of by EPSA and AWEA is a consequence of the customer's economic decision not to build upgrades.

934. Many transmission providers assert that the costs and inequities of achieving the proposed planning redispatch outweigh any new benefits for point-to-point customers.[591] They state that the Commission's proposal is based on an erroneous assumption that redispatch is nearly always feasible; instead when redispatch is most desirable, generators operating at peak would not be available for redispatch.[592] Southern also explains that problems of insufficient transmission capacity cannot be avoided by redispatching generation because there is no guarantee that a redispatch solution will be available during real-time operations. Imperial argues that the personnel and modeling costs to transmission providers of calculating planning redispatch costs prior to a facilities study are too excessive. Xcel concludes from a NERC experiment on market redispatch that redispatch involving non-market-based or bilateral coordination with third parties to protect a delivery path is cumbersome, inefficient, and does not promote reliability.

935. Xcel states that its estimate of hours of planning redispatch is unlikely to be accurate given that it uses a static power flow that is created for a specific peak hour and a specific off-peak hour in a given year. Commenters state that planning redispatch service should not be a guaranteed service because generation or transmission availability, system loads, loop flows from adjoining systems, weather, and fuel availability all entail a component of risk that should not be pushed back on the transmission provider or its native load.[593]

936. Operators of systems that rely primarily on hydroelectric resources argue that planning redispatch should not be considered a viable option for their systems and they should be exempt from OATT planning redispatch obligations because hydroelectric operators are unable to make long-term commitments that a resource will be available to relieve transmission constraints.[594] Bonneville states that the variability in water flows and the interdependence of the generating units contribute to the inability to predict future redispatch ability. Bonneville, WAPA and Bureau of Reclamation state that planning redispatch can conflict with federal obligations to operate federal dams and reservoirs in a manner that does not impact project purposes and provide preference in the sale of hydropower to its preference customers. Tacoma states that planning redispatch must be linked to market price indexes to work in a hydro-based system. Seattle states that in hydro-dominant systems fuel availability and fuel price risk undermine the feasibility of providing long-run redispatch cost estimates that reasonably reflect future costs. Seattle adds on reply that planning redispatch fails to address costs pertaining to fish species preservation, recreation and flood control impacts, increased risk of spill, or replacement power that are associated with hydroelectricity.

937. Morgan Stanley argues on reply that the Commission should not exempt hydroelectric system operators from providing planning redispatch; instead, factors unique to hydroelectric systems should be taken into account in determining how much planning redispatch a transmission provider can provide. In supplemental comments, PPM agrees with Morgan Stanley and adds that hydro-based systems, such as Bonneville's, are flexible enough for a transmission provider to use planning redispatch to create additional firm capacity.

938. In their reply comments, Utah Municipals and EPSA state that planning redispatch would not impair reliability because the OATT provisions do not require transmission providers to permit intentional overloading of lines. Since transmission providers are already required to provide planning redispatch now, Utah Municipals contend that any change in the sequence for studying the option cannot have an impact on reliability. EPSA argues that claims of adverse reliability impacts should be dismissed because transmission providers do not make these same claims when they redispatch to enable transmission service to meet their own load obligations. Utah Municipals state that reliability would be most enhanced by completely restricting access to the grid, a policy that Utah Municipals do not recommend because it would be extraordinarily costly and promote discrimination. In its reply comments, Entegra states that customers seeking planning redispatch are not seeking to shift a disproportionate share of the risks or costs to native load or other users of the system.

939. In its reply comments, EPSA further argues that the Commission should place the burden of showing unreliability in a particular instance on the transmission provider. EPSA also argues that transmission providers should not be allowed to delay service through feasibility studies. EPSA contends that planning redispatch will not delay needed system upgrades and, instead, will ensure optimized use of the existing system that will provide additional information about the system's capabilities to regional planning initiatives. In its reply comments, Morgan Stanley states that the Commission should establish clear standards as to the degree of expected reliability that appends to a firm transmission sale and allow transmission providers to sell as much of the system as can be sold on a firm basis, consistent with maintaining the reasonable standard.

940. EEI and some transmission providers add that the conditional firm product could result in an oversubscription of a transmission system in violation of NERC reliability standards that require the transmission system to be planned to meet all firm needs.[595] ELCON states that conditional firm service may not truly support long-term contracts for firm power but may lead to a greater volume of short-term trading.

Commission Determination

941. Many commenters are concerned that the options described in the NOPR will impair system reliability. We have taken these comments into account and have tailored the modifications to long-term point-to-point service so as to not impair system reliability. There are two important limitations that provide such protections. First, we make clear that transmission providers are not required to offer planning redispatch or conditional firm service if doing so would impair system reliability.[596] Second, as explained above and discussed in further detail below, we are limiting the time period under which either option is offered. We do so because forecasts of potential redispatch or interruption options become more

[591] *E.g.*, Duke, Entergy, Imperial, International Transmission, Salt River, Seattle, Southern, Tacoma, Northwest IOUs, Sacramento, Progress Energy, E.ON, Xcel, TVA, and EEI Reply.

[592] *E.g.,* Sacramento and TVA.

[593] *E.g.,* Progress Energy, E.ON, WAPA, Entergy, and MidAmerican.

[594] *E.g.*, Bonneville, Seattle, Public Power Council, and WAPA.

[595] *E.g.*, Ameren, Southern, and EEI.

[596] A transmission provider may not be able to provide conditional firm service without impairing the reliability of its system if it is required, for example, to manage many conditional firm point-to-point reservations across the same path. The ability of system operators to track, tag and manage curtailment of multiple conditional firm reservations is necessarily limited by time, human resources and other reliability-related duties of the operators.

speculative over time and to require a transmission provider to commit for a substantial period of time, subject to the uncertainty inherent in such long-term projecting, has the potential to degrade reliability. With these two limiting conditions, we find that neither the planning redispatch nor conditional firm option will degrade reliability and, as discussed above, that both are necessary to remedy undue discrimination.

942. We agree with a majority of commenters that over the long term, new resources should be supported by sufficient transmission capacity to deliver their output reliably. Imposing a planning redispatch or conditional firm obligation over the long-run would not be consistent with the need to increase the reliability of the grid or otherwise necessary to remedy undue discrimination. Rather, it would tend to degrade reliability over time, contrary to the public interest and the underlying goals of EPAct 2005. Projections of planning redispatch options and conditional firm conditions are more accurate in the near term and, hence, should facilitate the efficient use of existing resources without impairing reliability.

943. We therefore impose limits on the transmission provider's current planning redispatch obligations. We do so by removing the obligation to provide planning redispatch for an indefinite period as long as the redispatch is less expensive than the relevant transmission upgrades. Section 13.5 of the *pro forma* OATT could, in conjunction with rollover rights, allow for an extremely long-term obligation to provide planning redispatch in lieu of upgrading the transmission system. We find that this existing obligation may unreasonably harm reliability and provides incorrect incentives to delay necessary grid expansion. We emphasize that the obligation to provide planning redispatch applies only when the service can be provided reliably.

944. We also limit the time period over which a transmission provider must predict the system conditions or conditional hours that would apply to customers using the conditional firm option. We do so in recognition of the difficulty in attempting to forecast curtailment options over the long-term and the fact that there is no evidence that transmission providers perform similar forecasts for their native load customers. We do not, however, eliminate entirely the risk of predicting future system conditions or shift it in whole to the requesting transmission customer as requested by certain commenters. We believe that the transmission provider should retain responsibility for incorporating reasonable assumptions into its transmission models so that it can manage this risk, just as it currently manages the prediction risk in its ATC models.

945. We will now turn to certain clarifications and other issues raised by the commenters. We acknowledge that planning redispatch to support annual service may require redispatch of generation during the peak month or months. Since transmission providers plan their generation to meet their peak native load plus reserves, the transmission provider's resources may, in some cases, be fully employed to meet the needs of bundled retail native load and thus may not be available to provide redispatch during the peak period.[597] In such an instance, the unavailability of such resources to provide redispatch service will constitute a legitimate basis for denying planning redispatch service. However, we will not excuse the existing obligation that requires transmission providers to study any available planning redispatch, including redispatch that might provide some but not all of the service requested. Given that some transmission providers have acknowledged their own use of planning redispatch for their network resources,[598] the service must continue to be available to those seeking point-to-point service to ensure comparability.

946. We reiterate that the transmission provider remains obligated to provide planning redispatch from its resources as long as the planning redispatch does not (1) degrade or impair the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (2) interfere with the transmission provider's ability to meet prior firm contractual commitments to others.[599] We continue to believe these are the appropriate exceptions and will not adopt a broad and undefined reasonableness standard as suggested by Indianapolis Power. We agree with Southern that the transmission provider may consider the impact of the planning redispatch service in reducing its reserve margin below that necessary to maintain reliability or causing a single contingency to overload the system in determining whether the service can be reliably provided.

947. Further we will not excuse transmission providers from the obligation to manage multiple planning redispatch or conditional curtailment obligations simply because some commenters express concerns about planning and modeling impacts. While we do not take these concerns lightly, we believe they can be managed by transmission providers. The planning redispatch obligation has existed for ten years, and with it the potential for multiple planning redispatch requests. We have no evidence that transmission providers have been unable to manage the process. Moreover, by scaling back the time period for which transmission providers must plan for provision of redispatch, we have greatly reduced any planning and modeling impacts. We believe that whatever additional work the options cause with regard to planning and modeling, it is small and more than offset by the considerable value of the options which allow for more efficient use of the transmission system, expansion of long-term uses of the grid and remedying of undue discrimination.

948. Finally, we recognize the difficulty of predicting, over prolonged periods, whether hydroelectric resources will be available to provide redispatch. We agree with Morgan Stanley that factors unique to hydroelectric systems should be taken into account in determining how much planning redispatch a transmission provider can provide. For example, transmission providers operating hydro-based systems must predict both system load growth and water availability in order to determine whether resources will be available in the next few years to provide redispatch. We acknowledge that certain circumstances may in fact limit long-term redispatch on these systems due to increased prediction risks. We reiterate, however, that all transmission providers, including those operating hydro-based systems, are required to make a determination, regarding whether planning redispatch service can be provided consistent with system reliability based on the specific facts of a particular request for service. The fact that hydro-based systems may not be able to provide planning redispatch service under many circumstances should not necessarily limit the availability of conditional firm service on these systems. We expect that transmission providers with hydro-based systems will focus on provision of the conditional firm option in a manner consistent with their system conditions.

[597] *See, e.g.*, *Arizona Public Service Co.* v. *Idaho Power Co.*, 95 FERC ¶ 61,081 at 61,241 (2001) (resources projected to be unavailable during system peak month to provide planning redispatch).

[598] *E.g.*, Entergy.

[599] *See also* Order No. 888 at 31,739.

949. We also repeat that planning redispatch service does not need to be provided if doing so would impair the firmness of service to existing transmission customers. For example, pre-existing federal obligations, such as those described by Bonneville, WAPA and Bureau of Reclamation, would qualify as the type of firm commitments to others that would excuse transmission providers from the planning redispatch obligation to the extent that redispatch impaired service to these customers.

(B) Impact on Network Customers and Native Load

950. Several commenters argue that the use of planning redispatch may remove the ability to use reliability redispatch in real-time operations to respond to system contingencies, resulting in more curtailment of network and native load.[600] In addition to reducing availability of redispatch as an operational tool, NRECA contends that planning redispatch will reduce ATC for network service and the incentive to build new transmission. Several commenters state that planning redispatch may unfairly shift costs to network and native load customers.[601] Progress Energy argues that such a mandate places the power grid in serious jeopardy because the system has not been designed to handle the redispatch planning model. Progress Energy and Nevada Companies state that the planning redispatch option could conflict with transmission providers' state resource planning obligations to reliably serve load at least cost. Exelon replies, however, that planning redispatch could increase flexibility for network customers by increasing the availability of point-to-point service across adjacent transmission systems to bring generation to network loads.

951. Some commenters argue that the conditional firm option would adversely impact system reliability by subjecting firm customers to additional curtailments once conditional curtailment hours are exceeded.[602] NRECA and Utah Municipals state that the conditional firm service will reduce the flexibility of network customers by preventing network customers from using secondary network service, a right that NRECA argues is protected by FPA section 217.

Commission Determination

952. We reiterate that transmission providers are not required to offer planning redispatch and conditional firm point-to-point service if doing so would impair the reliable service to firm customers, including native load and network customers. The concerns of the commenters regarding the impacts on native load, network and other existing firm uses are therefore misplaced.

953. Transmission providers are already obligated to provide planning redispatch service pursuant to Order No. 888 and thus arguments that the planning redispatch option will harm existing customers is equally misplaced. Indeed, under the limitation on the duration of planning redispatch service imposed in this Final Rule, transmission providers will be able to better manage the risks of curtailment for current users of the transmission grid. This is because the obligation to redispatch will no longer be an open-ended obligation. Customers will need to commit to upgrade the system or to have their service reassessed periodically. Both of these allow the transmission provider to better plan to serve needs reliably because it reduces the unknowns. With regard to NRECA's argument that planning redispatch will cause less flexibility in real-time and more potential for curtailments of network customers and bundled retail native load, all sales of point-to-point service could to some extent cause more curtailments of network customers and bundled retail native load. Our decision today limits the existing planning redispatch obligation for point-to-point service, rather than expanding it.

954. Similarly, the conditional firm option does not reduce the availability of secondary network service or the ability of network customers to temporarily undesignate network resources any more than short-term firm point-to-point service already reduces the availability of these network customer options. We see no reason to reject the conditional firm option so that transmission providers avoid offering higher-quality service such as conditional firm point-to-point service in order to retain the ability to offer lower-quality service such as secondary network service.

955. Finally, we believe that network customers can benefit from the use of the planning redispatch and conditional firm options available in a point-to-point transmission service request. As described below, long-term point-to-point service that employs the planning redispatch or conditional firm option would qualify as a network resource on any adjoining system importing that resource.

(3) Implementation of Planning Redispatch and Conditional Firm Options

956. Commenters raise various concerns regarding specific implementation issues associated with the planning redispatch and conditional firm options. We address those concerns below, but first provide an overview of the planning redispatch and conditional firm service required in this Final Rule in order to outline the new rights and obligations of transmission providers and customers. Following this overview, we address specific comments relating to the service.

957. Pursuant to the modified obligations adopted in this Final Rule, where a request for long-term point-to-point firm transmission service is made and cannot be satisfied out of existing capacity, the transmission provider shall, at the request of the customer and in the system impact study, identify (1) the transmission upgrades necessary to provide the service, and (2) the options for providing service during the period prior to completion of those transmission upgrades. Additionally, if upgrades cannot be completed prior to expiration of the requested service term, the transmission provider shall, at the request of the customer and in the system impact study, identify options for providing the service during the requested term. The options studied by the transmission provider must include planning redispatch and conditional firm options.[603] The transmission provider, at its discretion, may study and offer a mix of planning redispatch and conditional firm options for a single service request. We provide further detail on each required option below.

958. If the transmission provider determines that planning redispatch is available, it shall provide the customer with non-binding estimates of the incremental costs of redispatch and identify the relevant constrained flowgates for which redispatch will be provided. For the conditional firm option, the transmission provider shall identify the conditions and hours pursuant to which the service may be curtailed, using a secondary network curtailment priority, to maintain reliability. Specifically, the transmission provider shall identify (1) the specific

[600] *E.g.*, EEI, Duke, Imperial, LPPC, PNM–TNMP, Public Power Council, NRECA, NPPD, Southern, and Progress Energy.

[601] *E.g.*, EEI, TAPS, LDWP, MidAmerican, Southern, Community Power Alliance, and MISO Reply.

[602] *E.g.*, Duke, LPPC, NRECA, NPPD, Progress Energy, Southern, APPA, and South Carolina E&G.

[603] Although partial interim service is not addressed in this rulemaking, we note that the OATT continues to require this service, on an as available basis, if a multi-year service request is denied.

system condition(s) when conditional curtailment may apply and (2) the annual number of hours when conditional curtailment may apply. Customers agreeing to take conditional firm service must choose one of these options, conditions or hours.

959. Where the customer requests firm service for more than two years, but is unwilling to commit to a facilities study or the payment of network upgrade costs, the transmission provider shall identify and provide the planning redispatch or conditional firm options subject to the following limitation. The transmission provider shall have a periodic right to reassess (1) the planning redispatch required to keep the service firm or (2) the conditions or hours under which the transmission provider may conditionally curtail the service. This reassessment may occur every two years during the term of the service, *i.e.*, at the end of year two, year four, year six, and year eight of a ten-year service. The transmission provider may not implement reassessments during intervening periods nor may it reassess the conditions in order to amend the service agreement in an intervening year should it forego any biennial reassessment.[604]

960. The service agreement shall specify the relevant congested transmission facilities and whether the transmission provider will provide planning redispatch, a mix of planning redispatch and conditional firm, or conditional firm in order to provide the point-to-point transmission service. For the conditional firm option, customers must choose among and the service agreement must specify either (1) specific system condition(s) during which conditional curtailment may occur or (2) annual number of conditional curtailment hours during which conditional curtailment may occur. We deem that any service agreement that incorporates planning redispatch or conditional firm options is a non-conforming agreement and must be filed by the transmission provider pursuant to section 205 of the FPA. Additionally, transmission providers must file with the Commission any amendments to these service agreements that result from reassessments. If a transmission provider proposes to change the redispatch or conditional curtailment conditions due to a reassessment, the transmission provider must provide the reassessment study to the customer along with a narrative statement describing the study and reasons for changes to the curtailment conditions or redispatch requirements no later than 90 days prior to the date for imposition of these new conditions or requirements. The transmission provider shall assess the conditions based on two years of service or the continuation of the term of service, whichever is less.

961. In situations in which the customer commits to paying the costs associated with upgrades necessary to provide the service on a fully firm basis, the conditions or hours identified by the transmission provider shall remain in effect until such time as the upgrades have been completed. Also, for such customers, the service agreement shall specify the upgrade costs as determined through the facilities study.

(A) Eligibility for and Timing of Planning Redispatch and Conditional Firm Options

NOPR Proposal

962. In the NOPR, the Commission proposed that customers who request long-term firm point-to-point transmission service and have the service denied because of lack of ATC would be eligible to receive planning redispatch service or, if the Commission chose to adopt the conditional firm service option, conditional firm service. The Commission also proposed earlier evaluation of the planning redispatch option in the system impact study rather than in the facilities study. The Commission proposed that, if it were to adopt conditional firm service, the evaluation of conditional firm availability should occur prior to a system impact study or facilities study.

Comments

963. If the conditional firm option is required by the Commission, many commenters believe it should be a bridge product to span the gap between when the relevant transmission service request is being studied and when the relevant upgrades become operational.[605] These commenters state that a bridge product is appropriate because it would not depress funding for new transmission infrastructure and would better meet the NOPR's and Congress' grid expansion objectives. In their view, use of a bridge product would avoid equity and free rider problems that may occur if a conditional firm customer is taking long-term service and the transmission system is upgraded during that service. They also argue that the bridge product would better allow for transmission providers to judge the likelihood of curtailment and avoid complicated system modeling and planning issues; as well as protect existing long-term transmission customers. Duke and Ameren state that an annual re-determination of the conditional period is necessary for a bridge product. If the upgrade has not been completed within a three year period, NRECA suggests that the customer be required to make a new long-term firm service request so the provider can update to reflect system conditions at that time.

964. Several commenters suggest that transmission providers should offer conditional firm service as both a bridge product and as a stand-alone long-term firm service.[606] Where not used as a bridge service, several commenters state that it should be limited to reservations that do not have rollover rights.[607] Duke argues that the service duration for non-bridge service should be one year, but with renewal rights that give the conditional firm customer a priority over other non-bridge conditional firm service customers seeking capacity. APPA supports one to two-year service offers.

965. In supplemental comments, EEI supports a voluntary conditional firm product with three types of service: A one-year product with no rollover rights; a bridge product for a term of more than one year that is provided until upgrades necessary to accommodate a firm service request are completed; and a non-bridge product of more than one year, with no rollover rights or transmission provider obligation to construct upgrades and subject to the transmission provider's periodic review of its system capability to provide such service. EEI contends that the Commission should encourage transmission providers to offer conditional firm service for more than one year without rollover rights to a customer that is not willing to take service of sufficient length to allow recovery of upgrades costs, if such service can be provided without affecting the reliability and quality of service to firm transmission customers.

966. In support of limitations on the term of conditional firm service, many

[604] For example, if a transmission provider opts to forego the reassessment at the end of year two, the transmission provider may not reassess the conditions of the service again until the end of year four of service for imposition of new conditions starting in year five.

[605] *E.g.*, Progress Energy Supplemental, PNM-TNMP Supplemental, LPPC Supplemental, APPA Supplemental, TAPS Supplemental, TDU Systems Supplemental, NRECA Supplemental, EEI Supplemental, Entergy Supplemental, Ameren Supplemental, Powerex Supplemental, and MISO Supplemental.

[606] *E.g.*, Bonneville Supplemental, PPL Supplemental, EPSA and AWEA Supplemental, EEI Supplemental, Barrick Supplemental, and Constellation Supplemental.

[607] *E.g.*, Xcel Supplemental, Duke Supplemental, and EEI Supplemental.

commenters state that analyzing and modeling system conditions will always be more accurate in the near term than in the long term.[608] EEI and Community Power Alliance believe that limitations on system modeling prevent many transmission providers from accurately evaluating their ability to provide conditional firm service over long periods. According to EEI, system conditions change on both the transmission provider's and neighboring systems substantially affecting the ability of the transmission provider to provide conditional firm service and the periods such service is subject to curtailment. While system loads can be predicted with a reasonable degree of accuracy for more than one year, other components of the prediction model, such as transmission and generator outages, typically are not determined more than a year in advance. For example, EEI states that members in the SERC region coordinate transmission and generation outages in a 13-month planning horizon. Duke states that the ability to model the system varies significantly by region. Entergy and MidAmerican believe that system modeling limitations would present serious reliability problems if transmission providers were required to offer a multi-year conditional firm transmission product because even the most advanced modeling software cannot predict long-term conditions that may affect service. Entergy and MidAmerican propose that the Commission allow transmission providers to update the curtailment criteria for a reservation, to reflect, among other things, changing load assumptions and forecasts over time. MidAmerican argues that without annual reevaluation there would be cost shifts to other firm customers. In its reply comments, MidAmerican explains that this reevaluation can only occur when the actual data becomes available for projecting potential curtailment hours.

967. If a transmission provider offers conditional firm service based on specified system conditions, Bonneville states in supplemental comments that limitations on modeling do not present a problem. If, however, the service is based on a maximum number of conditional curtailment hours per year, Bonneville believes that modeling presents problems in offering longer-term service. Bonneville states that forecasting the number of hours of conditional firm service requires great analysis. To remedy this, Bonneville suggests allowing the transmission provider to make conditional firm offers under which the transmission provider could periodically adjust the number of conditional curtailment hours.

968. In supplemental comments, Constellation proposes that the Commission require transmission providers to offer two types of conditional firm service: service for less than the service term eligible for rollover rights (*e.g.*, five years) if customers do not agree to pay for transmission upgrades; and service for five years or longer with a rebuttable presumption that the customer is obligated to pay for upgrades that are both economic and necessary to relieve the constraint that prevents its service from being fully firm.[609] EPSA and AWEA maintain that it is critical that the conditions be defined, and remain unchanged, for the term of the service agreement in order to obtain financing of new projects. EPSA and AWEA also propose that, if the contingency is removed during the life of the customer's conditional firm service, the service should convert to traditional firm service. Williams, EPSA and AWEA argue that up-front commitment to continue the conditions for the entirety of a long-term service agreement would take no greater risk than transmission providers take today in committing to other long-term firm transmission service. EPSA and AWEA state that limited term conditional firm service should pose no problems based on system modeling.

969. Several commenters believe that there is no need for any type of special rules for conditional firm customers taking bridge service and required to pay extremely expensive upgrades.[610] If the Commission abandons the ''higher of'' pricing principle for upgrades, these commenters suggest that any new pricing policies should be consistent with cost-causation principles and not result in any improper socialization.[611] Other commenters argue for special rules when upgrades are extremely expensive.[612] Xcel states that customers should have the option to take short-term conditional firm service that would remain subject to limitation and curtailment if upgrades are too expensive. Constellation proposes that customers taking the longer-term service should have the opportunity to show that upgrades would not be just and reasonable given the relevant circumstances, *e.g.*, the cost of upgrades for a single service request is $300 million. If the Commission determines that the bridge requirement in a particular circumstance is unjust and unreasonable, Constellation proposes that the transmission provider would provide the service for the requested term, but there would be no obligation for the transmission customer to pay for such upgrades, and the service would not be eligible for rollover. NRECA contends that instances in which special rules apply should be extremely rare and are best addressed by the transmission provider and customers on an *ad hoc* basis.

970. Commenters recognize that upgrades required under a bridge conditional firm option could create lumpiness problems,[613] but most commenters suggest that this problem is not unique to the conditional firm option, nor can it be resolved through use of the option.[614] These commenters support continuation of the Commission's existing policies with regard to lumpiness issues, and some suggest the need to address the issue as it pertains to all upgrades in a future proceeding.[615] In contrast, a few commenters suggest that the Commission should address the lumpiness issue with regard to conditional firm service. PPL, EPSA and AWEA state that the transmission provider should be required to pay the costs of any incremental lumpiness associated with upgrades and the service request. BP Energy contends that any lumpy capacity needs to be resolved on a bilateral contractual basis. Powerex suggests using an ''open season'' process to finance expensive and lumpy upgrades. California Commission supports prorating large lumpy

[608] *E.g.*, Nevada Companies Supplemental, TDU Systems Supplemental, LPPC Supplemental, Ameren Supplemental, Community Power Alliance Supplemental, MISO Supplemental, PNM-TNMP Supplemental, NRECA Supplemental, and Xcel Supplemental.

[609] EPSA and AWEA endorse Constellation's approach in defining and delineating the two forms of conditional firm service.

[610] *E.g.*, Nevada Companies Supplemental, Duke Supplemental, Bonneville Supplemental, Powerex Supplemental, BP Energy Supplemental, MISO Supplemental, PNM–TNMP Supplemental, Entergy Supplemental, Community Power Alliance Supplemental, and Southern Supplemental.

[611] Proposals regarding the ''higher of'' pricing policy are discussed below.

[612] *E.g.*, Xcel Supplemental, Constellation Supplemental, and NRECA Supplemental.

[613] In the November 15 Notice, the Commission described an example of lumpy capacity as upgrades to provide a requested 100 MW of point-to-point service that results in 1,000 MW of additional transmission capacity.

[614] *E.g.*, EEI Supplemental, Xcel Supplemental, APPA Supplemental, Bonneville Supplemental, LPPC Supplemental, NRECA Supplemental, Progress Energy Supplemental, Duke Supplemental, Ameren Supplemental, Entergy Supplemental, Community Power Alliance Supplemental, MISO Supplemental, Williams Supplemental, and PNM-TNMP Supplemental.

[615] *E.g.*, LPPC Supplemental, Bonneville Supplemental, and EEI Supplemental.

upgrades over a large base of new customers, to the extent that it is non-discriminatory and fiscally sound.

971. In supplemental comments, Nevada Companies urge that the time period of a conditional firm bridge product should be left up to the discretion of each transmission provider. They suggest that most, if not all, transmission providers should be able to offer a conditional firm service for a one-year period and most should be able to offer it for longer periods. Nevada Companies state that they should be able to provide conditional firm service in their control areas for longer periods, possibly for up to five years in some circumstances and in certain locations.

972. BP Energy and Williams disagree that conditional firm service should be a bridge product. They state that such a limitation would provide additional opportunities for undue discrimination and limit competitive alternatives used to serve customer load. According to California Commission, conditional firm service needs to be available for long-term requests unless there exists a valid, proven reason why conditions make it physically or economically impossible to guarantee such service. California Commission states that some limitations on modeling should be accepted as justification for not providing conditional firm or related services only if such provisions for load growth are nondiscriminatory, justified and contractually sound.

973. Commenters take both sides on whether planning redispatch should be evaluated before the customer is obligated to incur the costs and delays of a facilities study. EPSA argues that evaluation prior to a facility study meets nondiscrimination requirements given the methods used by transmission owners to evaluate planning redispatch for their own needs. In its reply comments, Exelon supports the minor changes to planning redispatch proposed by the Commission, including the earlier study of planning redispatch options in the system impact study, and states that these changes will expand choices for customers. EEI states that requiring an offer of planning redispatch prior to completion of a facilities study would be unduly preferential to point-to-point customers because transmission providers consider the costs of network upgrades and the impacts on system reliability before choosing planning redispatch for their native load. Southern points to the internal inconsistencies of the NOPR that on one hand seek to expedite the study process and on the other hand would require a planning redispatch study provision that would slow the study process.

974. EEI states that the vast majority of facilities studies show that the embedded cost of transmission service is higher than the incremental amortized cost of upgrades. Thus, EEI argues that the Commission's proposal to reform planning redispatch could lead to uneconomic decisions by the customer as well as provide disincentives to upgrade and expand transmission infrastructure.[616] In their reply comments, Utah Municipals respond that most of the time the embedded cost of transmission is higher than the costs of upgrades, adding that customers find requests for a transmission upgrades to be a time consuming and costly impediment to transmission access. Further, Utah Municipals add that limited and occasional redispatch or curtailment, would be more economically efficient than the construction of transmission facilities most of the time.

975. Several commenters state that it would be extremely burdensome to develop, at the system impact study stage, a reliable estimate of the number of hours of redispatch and the cost of the planning redispatch.[617] These commenters state that this would require substantial investment in probabilistic studies of equipment availability and extensive training of personnel and expansion of data collection, yet still would not provide reliable estimates of the number of hours or costs of the service. MISO states that at a minimum, this would require two years to implement.

976. EEI asserts that conditional firm service should be determined based on system impact studies and facilities studies so that the customer can evaluate the costs of upgrades versus the lack of reliability of the conditional firm service. EEI and others also propose that conditional firm service only be available when upgrades cannot be completed during the term of service or during the period prior to completion of transmission upgrades.[618] In its reply comments, Bonneville disagrees that conditional firm service should be an interim service available only when the customer has agreed to pay for upgrades, stating that such a requirement would undercut the value of conditional firm service. Bonneville adds that, for example, the costs to build upgrades in order to resolve a constraint in a two-month period could raise the costs of the conditional firm service to a prohibitive level for little additional benefit to the customer.

Commission Determination

977. As we explain above, the Commission finds that both planning redispatch and conditional firm point-to-point service must be offered under certain circumstances for the provision of reliable and non-discriminatory point-to-point transmission service. We set forth below the parameters of this service, keeping in mind the concerns expressed by commenters.

978. First, the planning redispatch and conditional firm options need only be made available to customers who request firm point-to-point service of more than a year in duration. When the requested firm point-to-point service is not available and the customer agrees to a system impact study, the transmission provider must evaluate the planning redispatch and conditional firm option at the customer's request. If the customer requests study of the planning redispatch or conditional firm options, the system impact study must identify the following: (1) The system constraints, identified by transmission facility or flowgate, causing the need for the system impact study; (2) additional direct assignment facilities or network upgrades required to provide the requested service; (3) redispatch options, including an estimate of the incremental costs of redispatch and the relevant congested transmission facilities for which redispatch will be provided; and (4) conditional firm options, including the number of conditional curtailment hours and the specific system conditions during which conditional curtailment may occur. Transmission providers may recover the costs of studying these options through the system impact study agreement.

979. Second, we adopt limitations on the nature of the planning redispatch and conditional firm options to reflect the two different types of customers that may request the service: customers who support the construction of upgrades and those who do not.

980. For customers supporting the construction of upgrades, the planning redispatch or conditional firm options will serve as a bridge until upgrades are constructed to remedy the congested transmission facilities. For these customers, the transmission provider must offer planning redispatch or conditional firm service until the time when the upgrades are constructed. The conditions or redispatch applicable to this period must be specified in the service agreement and are not subject to change. We impose this requirement

[616] *E.g.*, Xcel, PPM, and BP Energy.

[617] *E.g.*, EEI, Southern, TVA, SPP, E.ON, and MISO.

[618] *E.g.*, APPA, PNM–TNMP, and Southern.

because customers who commit to support transmission upgrades are typically those financing and constructing new resources. These customers require certainty both with regard to upgrade costs and, before upgrades can be constructed, the redispatch requirements or curtailment conditions that may apply to their service. We disagree with Williams and BP Energy that requiring transmission providers to offer this bridge product will present more opportunities for undue discrimination. As we note above, available information on transmission providers' current uses of redispatch and curtailment plans for their retail native load indicates that the mechanisms are used for relatively short periods of time until upgrades are completed to resolve the transmission insufficiencies. Comparable services for long-term point-to-point customers should therefore be similarly limited to shorter time periods or otherwise linked to transmission upgrades.

981. For customers choosing not to support the construction of new facilities, the planning redispatch or conditional firm options also must be made available as a reassessment product, *i.e.*, subject to certain limitations. Although many transmission providers argue that planning redispatch and conditional firm service should be offered only to customers who seek to upgrade the grid, we disagree. We find that there are legitimate circumstances under which customers may not choose to support system upgrades—either because the costs of construction are too high or because the term of service (*e.g.*, less than five years) does not merit the construction of additional facilities. We will therefore make planning redispatch and conditional firm service available to such customers, but subject to certain limitations to reflect the nature of the services. Specifically, we must select a limitation on the term for the conditions that permit interruption or redispatch, given that, for these customers, the term is not circumscribed by the period during which upgrades are constructed. We adopt two years as the appropriate time period to allow the transmission provider to reassess the conditions under which planning redispatch or conditional firm service is provided. The transmission provider will retain the right to reassess the planning redispatch and conditional firm option after the first two years of service, and every two years thereafter. The transmission provider shall reassess (1) the redispatch required to keep the service firm or (2) the conditions or hours under which the transmission provider may conditionally curtail the service. The customer will receive service for the requested term unless the transmission provider determines through its biennial reassessment that the firm point-to-point service can no longer be reliably provided. The customer may also choose to terminate the service at the time of reassessment if the service no longer meets it needs.

982. We select two years as providing a reasonable balance between the concerns of potential customers and transmission providers. We recognize that a shorter period would increase the reliability of predictions, as sought by certain transmission providers, but find that a two-year period is consistent with the bridge concept, given that two years is often less than the typical time to construct new facilities. While this is a shorter period than some transmission customers would desire, customers who require greater certainty over the long-term can obtain that certainty by agreeing to support the construction of new facilities. In the long run, all firm transmission customers, including conditional firm customers, should support the expansion of the grid to reliably serve load.

983. We decline to adopt any of the suggestions to address unique circumstances that may arise in which upgrades are prohibitively expensive. Specifically, we will not adopt Constellation's suggestion that customers be able to rebut the presumption that required upgrades are just and reasonable. In this Final Rule, we provide customers with the option of obtaining planning redispatch or conditional firm service for a long term, with the ability to roll over a five-year or longer reservation, subject to a limitation that the underlying restrictions on the service, *i.e.*, the conditions for redispatch or curtailment, may be reassessed by the transmission provider every two years. We believe that this option is superior to that proposed by Constellation because it will provide the customer with rollover rights while ensuring that transmission providers can reliably operate their transmission systems. Additionally, since issues of lumpy capacity are present in the provision of transmission services generally, we will not address such issues in this Final Rule as they do not present issues unique to planning redispatch or conditional firm options.

984. Contrary to the assertion of several commenters, we believe that transmission providers would take greater risk in committing to conditions for the entire term of a 10-year conditional option than they take today in committing to provide unconditioned firm point-to-point transmission service for a similar period. Planning for reliable service for existing transmission customers is a difficult process, but it is much more difficult to plan over an extended long-term period for reliable service when the service is firm for most of the hours of the year and less firm for other hours. This is because many transmission providers use annual hourly peak load for two to 10-year planning purposes. They would need to substantially change their planning methods to ensure no change in service for a conditional firm customer that is not expected to be served during the peak hour. We therefore adopt a two year assessment window to provide an appropriate degree of flexibility for transmission providers' planning needs.

985. We acknowledge, however, that some commenters, such as Bonneville and Nevada Power, state that they may be able to provide conditional firm service over a period longer than two years, without the need for reassessment. The Commission encourages the provision of planning redispatch or conditional firm service for longer periods where it is practical. In the event a transmission provider is able to extend the assessment period, we will allow the transmission provider to waive or extend its right to reassess the availability of the option, provided that the waiver or extension is provided consistently for all similarly situated service.

986. With regard to timing of the study of planning redispatch and conditional firm options, the Commission finds that study of both options is appropriate in the system impact study. The obligation for the transmission provider to study planning redispatch options in the system impact phase is already present in the existing OATT.[619] The Commission clarifies in this Final Rule the specific requirements necessary to meet this obligation. Transmission providers, when requested by potential customers, must provide non-binding estimates of the incremental costs of planning redispatch and identify the relevant congested transmission facilities for which redispatch will be provided. Transmission providers will not be required to estimate the number of hours of redispatch that may be required to accommodate the requested service as proposed in the NOPR. The Commission is persuaded by commenters that such an estimate is of limited use to potential customers and is difficult, expensive and time consuming for transmission

[619] *See pro forma* OATT section 19.3.

providers to calculate with any accuracy.

987. Finally, the Commission disagrees that the study of planning redispatch options must necessarily go hand in hand with the study of the costs and construction requirements of facility upgrades. Again, the obligation to study planning redispatch in the system impact study is not new. Our action in reinforcing this existing obligation cannot violate comparability or, in itself, cause the slowing of study processes. We have moved to a later study of conditional firm options so that both options can be studied in tandem. Furthermore, we note that the structure of the reassessment product requires the study of both options at the system impact study phase, since by definition customers opting for the reassessment product are not likely to enter into a facilities study agreement. We acknowledge that the few changes that we are making to the planning redispatch obligation may increase requests for study of the option and certainly the new conditional firm option will need more study than in the past. While we recognize the tension between the adoption of requirements to speed study completion and the increase in studies' complexity caused by the conditional firm option,[620] we will not forego a beneficial new option for customers because of this tension. We expect that transmission providers will be diligent in completing the system impact studies and in bringing to our attention any difficulties in meeting deadlines caused by the study of the two options.

(B) Who Must Provide Planning Redispatch and Conditional Firm

NOPR Proposal

988. In the NOPR, the Commission requested comment on the applicability of these two options to transmission providers who operate as RTOs and ISOs. The Commission also requested comment on which resources should be required in the provision of planning redispatch. First, the Commission proposed that the planning redispatch requirement apply to the redispatch of the transmission provider's own generation resources, but not to obligate transmission providers to purchase new resources to provide the service. If a transmission provider cannot accommodate a long-term firm point-to-point transmission request through planning redispatch, the Commission proposed requiring the transmission provider to identify additional generators in other control areas that could relieve the constraint. The Commission also requested comment on whether the planning redispatch obligation should be expanded to require the use of network customer resources in addition to transmission provider resources or expanded to require that transmission providers contract to purchase off-system resources to facilitate the planning redispatch.

(i) Application to RTOs and ISOs

Comments

989. RTOs state that reforms regarding planning redispatch and conditional firm services are unnecessary in RTO markets with financial congestion management because these markets already provide sufficient redispatch inside RTOs and sufficient interconnection service for generators located at RTO boundaries to address the Commission's point-to-point service concerns.[621] Ameren and MISO add that the options could disrupt the distribution of financial transmission rights in RTO markets. Others disagree and argue that planning redispatch should be used by RTOs to define the current and future operational environment to ensure that systems are not overbuilt.[622] AWEA contends that, since RTOs and ISOs vary considerably in the services they offer, RTOs and ISOs should be required to demonstrate that their services are consistent with or superior to planning redispatch and conditional firm services. In particular, AWEA argues that RTOs that do not provide financial rights should be required to provide both of these services. Exelon states on reply that the Commission has proposed minor changes to the existing planning redispatch requirement that should not be impractical or too burdensome for RTOs to administer.

990. In its reply comments, California Commission adds that capping the frequency or costs of redispatch in an RTO market would inappropriately shift the costs of congestion to others. Although SPP has successfully used planning redispatch to facilitate short-term firm transmission service and to address interim circumstances associated with long-term firm transmission service,[623] it argues that the Commission's proposed expanded planning redispatch service would slow its batch processing of transmission service, require significant investment of time to evaluate the options given the scope of an RTO, and create speculative redispatch estimates at best. SPP adds that RTOs should simply assist the customer with identification of planning redispatch options so that the customer can bilaterally contract with the generation owners of its choice.

991. MISO adds that conditional firm is inconsistent with RTO market mechanisms, requires burdensome changes to curtailment protocols and reliability coordinator's procedures, and would impact every tool used in real time for congestion management in RTOs. In its reply comments, MISO adds that adoption of conditional firm service would require revisions to seams agreement protocols. California Commission states on reply that the added administrative complexity of conditional firm service is unnecessary in the CAISO because the ISO's transmission service model makes no distinction between firm and non-firm service and provides prospective new customers with information to objectively estimate curtailments. FirstEnergy and MISO express concern regarding disruption of existing RTO communication protocols if these services are required in RTOs.

Commission Determination

992. Notwithstanding the requirements of section IV.C of this Final Rule, the Commission finds that it would be inappropriate to require RTOs and ISOs with real-time energy markets to adopt the provisions for conditional firm point-to-point service. Customers transacting in RTOs and ISOs are able to buy through transmission congestion in the RTOs' real-time energy markets and need no prior reservation in order to access transmission. Voluntary curtailment in order to access transmission is thus not an attractive option given the range of options available for customers transacting in RTOs and ISOs. Further, in RTOs and ISOs with financial transmission rights, conditional firm service may disrupt the distribution of these rights. We therefore believe that there is no need to reform existing RTO and ISO procedures to satisfy concerns underlying the adoption of the conditional firm option.

993. The Commission directs, however, RTOs and ISOs that already

[620] In section V.D.5.a, we adopt a requirement that transmission providers post metrics on their performance in processing system impact studies and facilities studies.

[621] *E.g.*, MISO, PJM, California Commission, and ISO New England.

[622] *E.g.*, AWEA, Indianapolis Power Reply, and Exelon Reply.

[623] *Citing* Attachment AC of the SPP OATT (Optimal Reservation Processing Method for Short Term Firm Transmission Services).

provide planning redispatch pursuant to section 13.5 of the *pro forma* OATT to modify the relevant provisions of their tariffs consistent with our directives in this Final Rule.[624] RTOs and ISOs need not amend their tariffs if the Commission has previously found that these tariffs were just and reasonable without the inclusion of *pro forma* section 13.5 planning redispatch provisions. We will not require incorporation of the more limited planning redispatch obligations adopted in this Final Rule if RTOs and ISOs have already been excused from the planning redispatch obligations of the existing *pro forma* OATT.

(ii) Generation Resources Required for Planning Redispatch

Comments

994. Most commenters agree that resources in addition to the transmission provider's resources can and should participate in the provision of planning redispatch. Commenters differ as to whether this participation should be mandatory or voluntary. A few commenters maintain that participation by resources outside the transmission provider's control area could have adverse impacts on reliability in the control area.[625]

995. In arguing for mandatory participation, EEI and others contend that all generation resources owned or operated by all jurisdictional transmission customers in the control area or balancing authority area should be obligated to redispatch to accommodate new requests for service in order to avoid undue discrimination.[626] Exelon argues that transmission providers should redispatch resources of its network customers, subject to appropriate compensation. SPP contends that generation affiliated with transmission owners that have transferred functional control of their transmission assets to an RTO should not have any greater planning redispatch obligation than unaffiliated generation. In its reply comments, Entergy states that the Commission at a minimum should continue to allow network customers to request that transmission providers redispatch network customer resources in order for the customer to designate a new network resource.

996. Others argue for a least-cost economic dispatch to relieve real-time system constraints, including not only the transmission provider's own resources and those of its network customers, but also all non-affiliated resources both within and outside its footprint that choose to be included.[627] EPSA explains that this redispatch would: Require transmission providers to solicit offers from resources to provide energy and perhaps ancillary services; be based on a resource's offer of service and take into account generating resource and transmission operating limits; include performance assurance terms, unit commitment procedures, billing, compensation and bidding protocols, confidentiality protections, and information-sharing protocols; and dispute resolution procedures to avoid disputes rising to the level that would require judicial or regulatory intervention. AWEA supports Deseret's OATT provisions that require the transmission provider to relieve constraints by the least cost means, whether by seeking a change in generation output from the transmission provider's merchant function or from any other feasible generator. Williams suggests that independent generators must be allowed to participate in the provision of planning redispatch service through submission of a formulary rate to the transmission provider. If the Commission intends to have non-affiliated generators participate in planning redispatch, PPL states that the Commission should require transmission providers to negotiate agreements with generators on their systems.

997. TranServ, MidAmerican, and Nevada Companies support a planning redispatch service similar to that employed by the Mid-Continent Area Power Pool, whereby customers arrange for their own redispatch through bilateral or centralized energy markets and submit plans for approval to their transmission provider and reliability coordinator.

998. Several commenters discuss the need for market development in conjunction with the planning redispatch obligation. TranServ and Xcel state that the planning redispatch option may force transmission providers without generation assets to develop some form of energy market to arrive at the costs of redispatch. Southern and Progress Energy add that forced adoption of such a market would raise significant political opposition and be contrary to the Commission's commitment in the NOPR to avoid such restructuring.

999. EPSA, AWEA and PJM support such market development. When a generator in another control area is called upon to relieve a constraint in regions not administered by an RTO, PJM states that the Commission must direct the development of an alternate LMP pricing scheme to establish ''system marginal costs'' that are consistent with transparent generator pricing in RTO markets. EPSA and PJM argue that vertically integrated utilities in non-RTO areas should turn over functional control of their dispatch function to a disinterested entity or replicate the transparency by publishing generation dispatch. EPSA suggests that the Commission require this transparency to ensure nondiscriminatory redispatch.

1000. A few commenters state that any requirement for the transmission provider to purchase generation from outside the control area to facilitate planning redispatch is functionally unworkable and would adversely impact reliability.[628] EEI supports the Commission's proposal to have transmission providers identify off-system resources that could provide planning redispatch but requests clarification that no additional investigations or studies are required to identify these additional options. MidAmerican adds that the coordinated, open and transparent planning provisions of the NOPR should provide customers with the ability to identify off-system resources. EEI and Southern state that any redispatch on adjacent systems should be arranged by transmission customers and the service should be curtailed prior to other firm uses of the system if the off-system generator fails to perform. WAPA and Bonneville argue against the use of off-system redispatch, stating that lack of control over these resources could cause reliability problems on the originating transmission system. WAPA also believes that off-system redispatch would not provide the price certainty needed by customers because the redispatched megawatts will differ based on the transmission system parameters, and customers would be required to pay for any loop flow resulting from the off-system redispatch.

1001. In its reply comments, EEI adds that a requirement for transmission providers to solicit planning redispatch

[624] This includes the transmission provider's obligation to post monthly redispatch costs for each transmission facility over which planning and reliability redispatch are provided.

[625] *E.g.*, Ameren, PNM–TNMP, Xcel, and WAPA.

[626] *E.g.*, Southern, FirstEnergy, MidAmerican, and Community Power Alliance.

[627] *E.g.*, AWEA, Project for Sustainable FERC Energy Policy, Exelon, Powerex, Constellation, Williams, Sempra Global, PJM, EPSA, and Entegra Reply. Sempra Global contends that the Commission should require transmission providers to offer redispatch of non-affiliated resources both within and outside its footprint, subject to pre-existing contractual commitments.

[628] *E.g.*, Xcel, PNM–TNMP, and Public Power Council Reply.

proposals from generators inside and outside their control areas would require that transmission personnel become involved in generation and power sales matters in violation of the Commission's Standards of Conduct. Duke argues on reply that such an approach would require that third party generators reveal their costs to the transmission provider and that a means of estimating costs for all generators subject to planning redispatch would need to be set forth in the *pro forma* OATT.

1002. LPPC, APPA and TAPS oppose any requirement that transmission providers redispatch their network customer's resources as well as their own to provide planning redispatch, stating that this action would appropriate resources beyond the Commission's jurisdiction, result in endless conflict between transmission providers and resource owners, and interfere with network customer's use of their limited resources.

Commission Determination

1003. Order No. 888 compelled transmission providers to provide planning redispatch from their own resources.[629] The Commission declines to expand that obligation to require transmission providers to solicit third party resources in order to provide planning redispatch. We will, however, require transmission providers to identify in the system impact study (1) generation resources located within the transmission provider's control area, including its own resources, that can relieve the congested transmission facility at issue, and (2) the impact of each identified resource on the congested facilities, *e.g.*, the generator shift factor. The resources identified in the system impact study need not be available to provide the redispatch. Customers must simply be provided with the set of generators that could, if available, make a significant contribution toward relieving the constrained facility at issue. This information, in addition to the information provided through congestion planning studies, will provide the necessary information to customers wishing to solicit third party resources to relieve congested facilities in order to accommodate long-term firm point-to-point service. We note that this information is readily accessible by the transmission provider, as it is the same information used to determine *pro rata* curtailments of firm resources in contingency situations.

1004. In addition to identifying generation resources within the control area, the Commission also requires identification of resources outside the control area that may be able to relieve congested transmission facilities. To the extent the transmission provider is aware of generation resources outside of its control area that can relieve the constraint, the transmission provider must inform the customer of these resources. To be clear, this does not require the transmission provider to undertake any additional investigation or study to identify generation options located outside of the control area. To the extent the transmission provider has such information, however, it must provide it to the customer.

1005. The Commission will not mandate the use of network customer resources or other third party resources in the provision of planning redispatch.[630] If they choose, network customers and third parties may voluntarily provide planning redispatch services. A seller is free to post its price to relieve a specific congested transmission facility and its ability to relieve the congestion. To facilitate provision of such service by third parties, we direct transmission providers to modify their OASIS sites to allow for posting of these third party offers. Accordingly, we direct transmission providers to work in conjunction with NAESB to develop this new OASIS functionality and any necessary business practice standards. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards.

1006. Customers may then contract in advance with these third parties or use their own resources to secure planning redispatch services in lieu of or in addition to service from the transmission provider. In this way, customers can arrange for their own planning redispatch through bilateral markets and submit plans for approval to their transmission provider and reliability coordinator. The arrangements must, however, be sufficiently detailed and coordinated with the transmission provider to ensure that reliability is maintained.

1007. We therefore direct in this Final Rule that transmission providers work with customers to facilitate the use of third party generation, where available, in provision of planning redispatch. This entails review of redispatch plans submitted by customers, coordination between the transmission provider and reliability coordinator, and signaling third party generators when the redispatch is needed. These arrangements will require close coordination between the transmission provider, third party generators and transmission customers. The arrangements must be sufficiently detailed to allow the transmission provider to maintain reliability. Although we will not allow transmission providers to unreasonably deny customers the use of third-party resources to provide planning redispatch, it is the customers' ultimate responsibility to ensure that all the necessary contractual and technical arrangements are in place to maintain reliability. We clarify for Entergy that this would allow transmission providers to continue to provide planning redispatch for network customers from the network customers' resources. We also clarify that transmission providers may curtail transmission customers if a third-party resource fails to perform its contractual redispatch obligation. This or any other remedy for non-performance must be specified in writing between the parties prior to commencement of the service.

1008. For the reasons discussed below regarding the TDA proposal, we decline to adopt the bid-based redispatch model suggested by EPSA. In section V.C.1 of this Final Rule, we similarly reject proposals to impose LMP and independent control of the dispatch function. We believe that a bid-based generation market design is not necessary to remedy undue discrimination in the provision of transmission service. We also believe that our modifications to the planning redispatch requirement, including the OASIS changes directed herein and the requirement that transmission providers make available information on generators capable of providing planning redispatch, will provide potential customers with greater information about redispatch choices and enable greater opportunities for planning redispatch and comparable service.

[629] *See pro forma* OATT section 13.5. With respect to SPP's assertion that transmission owners' affiliated generation should have no greater redispatch obligations than unaffiliated generation in RTOs, we find that relevant redispatch obligations in the RTO tariff and transmission owners' tariffs govern this issue. *See Southwest Power Pool, Inc.,* 110 FERC ¶ 61,133 at P 17 (2005) (rejecting proposed provisions that would have removed the obligation for transmission owners to provide planning redispatch).

[630] Network customers will continue, however, to be obligated to make their network resources available to the transmission provider for reliability redispatch in real time.

(C) Pricing of Planning Redispatch

NOPR Proposal

1009. In the NOPR, the Commission sought comment on which type of redispatch pricing would ensure effective use of the planning redispatch option. The Commission described one type of pricing, a formula rate, to include a MW quantity, the incremental cost of fuel at the point of delivery, and the decremental cost of fuel at the point of receipt capped at the price of fuel. The Commission sought further comment on whether it would facilitate planning redispatch to base calculations of the various costs for input into the formula on the difference between the cost of ramping up a generator at the point of delivery and ramping down a generator at the point of receipt. The Commission also described a redispatch pricing proposal to calculate redispatch charges monthly and charge the higher of actual redispatch costs or the OATT rate each month made by PacifiCorp in response to the NOI.

Comments

1010. While many specific comments were received on the pricing of planning redispatch service, there is little consensus on this subject. Several commenters state that pricing challenges associated with planning redispatch are difficult if not insurmountable.[631]

1011. MidAmerican and EEI argue that the current cap on planning redispatch at the costs of upgrades should be removed because a customer will always choose planning redispatch and the risks that redispatch costs exceed construction costs falls to the transmission provider and is either unrecoverable or passed on to other customers.

1012. According to several commenters, requiring the transmission provider to establish a standard fee for planning redispatch, either on the overall system or on a path-by-path basis, would accomplish cost certainty for the customer and hold the transmission provider accountable for the accuracy of the studies used to assess redispatch requirements.[632] These commenters support a standardized formula-rate for planning redispatch or a capped amount at, or close to, the embedded cost rate. Entegra and TransAlta state that the redispatch pricing proposal may allow transmission providers discretion to charge redispatch costs without providing customers a practical way to verify that claimed redispatch costs have actually been incurred. PGP states that the Commission should allow for regional differences in planning redispatch pricing. APPA does not support a departure from the current redispatch pricing approach, while Seattle states that the existing section 13.5 is unworkable because the cost of planning redispatch is difficult to calculate for both historical and near-term operating horizons, much less over a multi-year planning horizon.

1013. EPSA and AWEA believe that the pricing mechanisms suggested in the NOPR would be open-ended and highly variable over the duration of the reservation and, thus, not meet the needs of customers. EPSA and AWEA assert that, consistent with Commission precedent,[633] a utility must identify and justify its costs in excess of average system costs before service commences in a manner that meets the customer's needs to charge a rate in excess of average system costs, *i.e.*, some customers may require a firm estimate upfront to obtain financing while others may be willing to negotiate a rate based on estimates.[634] EEI states on reply that the policy in American Electric Power related to an expansion cost rate, which is inapposite to redispatch costs because the costs of new construction are easier to estimate in advance than are the costs of planning redispatch. EEI contends that the planning redispatch customer's interest in price certainty is not a sufficient basis for shifting costs to other customers or to the transmission provider.

1014. EPSA and AWEA suggest that, when the cost of planning redispatch is estimated to exceed the transmission rate, the transmission provider should offer either: a formula rate for incremental redispatch costs with the number of hours of redispatch, the resources to be redispatched and the conditions under which redispatch would occur defined in advance or, an incremental cost rate determined at the time of the reservation to cover the reservation period that may include a risk adder for the transmission provider. Morgan Stanley argues that planning redispatch options should include the following: Redispatch priced at a market index; where market prices are not available, the price should be the incremental costs; full cost pricing should be allowed for ''life of service'' (total dollar cost for unlimited redispatch over the term of a contract) or fixed rate contracts for actual redispatch agreed to at the time of contracting; and redispatch costs provided from a third-party provider. Morgan Stanley opposes ''higher of'' pricing that would allow for monthly charges for redispatch costs or long-term firm transmission service rate.

1015. In contrast, many transmission providers and EEI ask the Commission to allow for recovery of actual costs of redispatch, rather than the estimated costs, with the customer obligated to pay all costs.[635] Since providing accurate estimates of redispatch costs and hours are difficult, especially with respect to longer-term service requests given the variability of fuel costs, transmission providers contend that they should not bear the risks of inaccurate cost estimates for a service that benefits only the point-to-point customer.[636] Indianapolis Power adds that planning redispatch should be priced to discourage inefficient dispatch of generation. In its reply comments, PPM agrees that planning redispatch is unworkable without certainty of cost recovery for the transmission provider, but believes that with enough information customers can evaluate the risks and gain certainty required for a workable product.

1016. Southern argues that the current pro forma OATT language unreasonably places the risk of uncertainty in estimating redispatch costs on the transmission provider and its native load customers, contrary to basic cost causation principles and native load protections in Order No. 888. Southern suggests that the Commission follow the approach in the Deseret and SPP tariffs, which allow for the transmission provider to recover its actual costs of redispatch. Ameren states that a standard per kWh fee is simpler to administer, but should be structured to recover all of the costs of planning redispatch, including opportunity costs.

1017. Various commenters argue that the Commission should allow the following redispatch costs to be recovered: Fuel; variable operations and maintenance; increased maintenance costs due to cycling; start-up and ramp-down costs; emergency purchases; costs of additional operating reserves; environmental costs; and lost opportunity costs.[637] MidAmerican also argues that a transmission provider should be able to recover the costs of

[631] *E.g.,* Powerex, Manitoba Hydro, Seattle, NRECA, Ameren, and E.ON.

[632] *E.g.,* Utah Municipals, Public Power Council, PPM, Entegra, Constellation, TransAlta and TAPS.

[633] *American Electric Power Service Corp,* 64 FERC ¶ 61,279 (1993) (*American Electric Power*).

[634] *Id.* at 62,976.

[635] *E.g.,* Southern, MidAmerican, Entergy, FirstEnergy, Ameren, Nevada Companies, E.ON, and South Carolina E&G.

[636] *E.g.,* EEI, Entergy, LPPC, NRECA, MidAmerican, Ameren, and FirstEnergy.

[637] *E.g.,* LDWP, EEI, Ameren, MidAmerican, and Southern.

redispatch energy purchased in response to a pre-schedule by a planning redispatch customer regardless of schedule changes by the customer and regardless of any *pro rata* curtailments affecting such customers due to system reliability.

1018. EEI and Southern argue that customers that choose planning redispatch should pay the cost of transmission service and the cost of redispatch. EEI asserts that allowing recovery of both costs is not prohibited ''and'' pricing because the services differ, as one is provided by the transmission system and one is provided by generators, and native load and network customers pay *pro rata* shares of reliability redispatch costs to relieve constraints on the system as well as the basic costs of transmission service. TAPS and TDU Systems take the opposite view and state that the Commission should require planning redispatch pricing consistent with the Commission's ''higher of'' or ''or pricing'' policy. In addition, they state that the redispatch charges must be capped up front at fixed dollars and hours at or close to the embedded cost rate.

1019. Arkansas Commission agrees with the PacifiCorp pricing method in which redispatch costs are recalculated monthly and customers are charged the higher of the redispatch cost rate or the monthly OATT transmission rate. TAPS states that this method avoids ''and'' pricing, but does not address the complexity or risks associated with determining redispatch costs over a long period. APPA argues that the PacifiCorp proposal, if applied after the fact, could lead to uncertainty and disruption of market transactions. Southern opposes any pricing method that caps the total costs that a planning redispatch customer would bear, including the PacifiCorp proposal, stating that caps allow the planning redispatch customer to shift costs to the transmission provider and its native load customers.

1020. E.ON points to an inherent problem in planning redispatch pricing: Transmission providers should be kept whole with regard to actual real-time redispatch costs but customers may not know until after the fact that the planning redispatch was not economic for their purposes. E.ON foresees difficulty in allocating redispatch costs among multiple planning redispatch service customers and requests that the Commission adopt a specific methodology for calculating each request's impact on the system.

Commission Determination

1021. Although there is no consensus regarding which form of pricing methodology is most appropriate for planning redispatch service, there is general agreement among the commenters that the current pricing rules fail to meet the needs of either customers or transmission providers and consequently fail to make planning redispatch an attractive means for customers to obtain access to the grid. Transmission providers and customers both express concern regarding the variability of redispatch costs. Customers worry that actual redispatch costs may greatly exceed estimates and thus seek cost certainty over the term of the service. Conversely, transmission providers claim that accurately estimating future redispatch costs for long duration service is extremely difficult. In fact, transmission providers state that the uncertainty in forecasting long-term redispatch costs is much greater than any uncertainty inherent in determining the costs of transmission upgrades.

1022. The Commission has carefully considered these comments and agrees that the current method for pricing planning redispatch service is no longer just, reasonable or not unduly discriminatory. The Commission takes three principal actions to address the concerns of customers and transmission providers.

1023. The Commission therefore adopts a new pricing method for planning redispatch service. We will no longer require the capping of redispatch costs over the term of the service at the costs of expansion. This change is inextricably linked with the change in the obligation to provide planning redispatch, *i.e.*, the removal of the open-ended requirement to provide planning redispatch as long as it is more economical than transmission upgrades. We have shortened the planning redispatch obligation to apply before upgrades are built as a bridge product or to apply as part of a reassessment product. In prior cases, the Commission expressed the view that capping cost recovery for long-term transmission service at the costs of expanding the transmission system provides an incentive for transmission providers to undertake expansion when it is warranted.[638] The expansion cost cap should not be applied to the bridge product because (1) upgrades will in fact be constructed and should be paid for by the customer under the ''higher of'' policy, and (2) an expansion cost cap does not serve as an incentive for expansion because the transmission provider already will have started the process of building transmission facilities for the customer who opts for the bridge product. If planning redispatch is provided as part of a reassessment product, the customer has chosen not to pay for upgrades and thus, the expansion cost cap cannot provide an incentive for transmission expansion.

1024. We will therefore adopt a new pricing methodology. We believe that the PacifiCorp proposal described in the NOPR is the one that balances the competing concerns of transmission customers and transmission providers. Under this pricing methodology, customers will have the option of paying (1) the higher of (a) actual incremental costs of redispatch or (b) the applicable embedded cost transmission rate on file with the Commission or (2) a fixed rate for redispatch to be negotiated by the transmission provider and customer and subject to a cap representing the total fixed and variable costs of the resources expected to provide the service. If the customer selects the higher of incremental cost or the embedded-cost rate, the transmission provider shall calculate the costs of redispatch monthly and charge the higher of redispatch or the embedded cost rate each month.

1025. We have selected a monthly comparison of embedded costs and redispatch costs on the basis of a number of factors. The Commission has rejected basing the comparison on the life of a long-term firm transmission contract.[639] For administrative efficiency, a transmission provider should be allowed to close its books and not be subject to possible refunds or surcharges at the end of its billing cycle. The standard billing cycle in the industry is one month. Allowing transmission providers to finalize accounting entries will provide certainty to both the transmission provider with regard to revenue recovery and to the transmission customer with regard to cost exposure. We therefore find that a monthly comparison of embedded and incremental cost is appropriate. This method retains ''higher of'' pricing for customers, but does not subject transmission providers to open-ended liability for refunds and otherwise should make planning redispatch service more attractive for transmission providers to provide. Further, given that redispatch often occurs only in selected time periods within a year (*e.g.*, during

[638] *See, e.g., Florida Power & Light Co.,* 70 FERC ¶ 61,158 at 61,484 (1995).

[639] *Id.* at 61,483.

the peak season, shoulder months, *etc.*), it is just and reasonable to allow the transmission provider to perform the higher of calculation in each month when the service is provided, not spread those costs over the entire year.

1026. For purposes of calculating planning redispatch charges, incremental costs shall include fuel or purchase power costs caused by ramping up generator(s) at the point of delivery and ramping down generator(s) at the point of receipt. Additionally, where applicable, transmission providers may specify in customer service agreements other incremental costs for inclusion in the monthly actual incremental costs, including opportunity costs. Identification and derivation of these costs must be included in the service agreement. We reiterate our existing requirement that all information necessary to calculate and verify opportunity costs must be made available to the transmission customer.[640] We clarify that the actual costs of redispatch need not be determined annually or at the time that the service agreement is executed; rather, actual redispatch cost should be determined on a monthly basis.

1027. With respect to MidAmerican's request to be able to recover the purchase power costs for a customer requiring planning redispatch, we reiterate that transmission providers are under no obligation to purchase power to provide planning redispatch services. Should the transmission provider take on the obligation to contract with a third party to provide planning redispatch at the customer's request, however, the customer should be obligated to pay the purchase power costs, including any reservation charge for the power. The flow-through of purchase power costs must be negotiated between customers and transmission providers in a stand-alone agreement if the transmission provider agrees to make purchases on the customer's behalf.

1028. The Commission will not adopt proposals suggested by several transmission providers to allow for recovery of the embedded cost transmission rate and the full costs of redispatch. The Commission's ''higher of'' pricing policy prohibits the transmission provider from charging both embedded costs and incremental costs such as redispatch costs.[641] We reject EEI's assertion that we should adopt such pricing because native load and network customers pay a load ratio share of redispatch costs and the embedded cost transmission rate. Planning redispatch differs from the reliability redispatch for which transmission providers are only obligated to provide network customers with ability to avoid real-time curtailments. Rather, planning redispatch is a means of creating additional transmission capacity,[642] not a generation service, and thus planning redispatch is appropriately priced by applying the Commission's ''or'' pricing policy. We decline to revisit that longstanding policy in this rulemaking.

1029. With respect to concerns that the expansion cost cap was adopted to provide rate certainty to customers over the term of the service,[643] we believe that the modified pricing policy adopted here will continue to provide appropriate certainty to customers, while also allowing transmission providers to recover just and reasonable costs. For customers purchasing the bridge product, the cost of redispatch will be incurred only during the initial term of the service agreement while new facilities are being constructed. During this term, the cost of redispatch service represents a legitimate cost of providing the service and therefore should be fully recoverable under the higher of policy. Although it is true that redispatch costs are difficult to project, and hence create uncertainty for customers, this does not mean that the transmission provider should not be allowed to recover the legitimate and verifiable costs of providing the service. Moreover, if the customer desires greater certainty regarding redispatch costs during this period, it can elect the fixed rate option discussed above and negotiate a fixed redispatch charge with the transmission provider. Once upgrades are constructed, however, the customer will receive the certainty of paying a fixed rate for transmission costs and, importantly, any expansion cost will be fixed at the time the initial service agreement is signed. Finally, for customers who do not select the bridge product because they do not want to fund upgrades, it would be unreasonable to cap the cost of redispatch at the cost of upgrades. In such an instance, the customer has elected to forego the price certainty that can be gained by funding the upgrades to remove the constraint that is causing the transmission provider to incur redispatch costs.

(D) Standards of Conduct and Planning Redispatch

NOPR Proposal

1030. In the NOPR, the Commission requested comment on the interaction of planning redispatch requirements with the Commission's Standards of Conduct.

Comments

1031. Commenters generally argue that the independent functioning requirement and the information sharing prohibitions under the Standards of Conduct are irreconcilable with the expanded planning redispatch proposal in the NOPR.[644] Southern, TranServ and Progress Energy contend that the planning redispatch option would require close coordination and communication with market participants including the marketing or energy affiliate, which may create confidentiality and Standards of Conduct problems. For instance, they state that close coordination and sharing of non-public transmission and customer information would be required to determine the generating units that can be redispatched, the impact that planned and forced outages of redispatched generators will have on the availability of transmission service and the transmission line loadings, and the costs of redispatch. Some commenters request that the Commission adopt an exception to the Standards of Conduct to permit communication between transmission providers and marketing and energy affiliates, acting as generation operators, for the transmission provider to instruct the generation operator to vary its generator's output.[645]

1032. MidAmerican suggests that it is unlikely that any communication protocols could be established that would both comply with the Commission's current Standards of Conduct and permit a transmission provider to coordinate with its marketing affiliate employees to arrange planning redispatch. Rather, MidAmerican argues that the transmission customer would have to waive the Standards of Conduct to enable the transmission function employees to share the necessary information with their marketing affiliate counterparts.

[640] *See* Order No. 888 at 31,740.

[641] *See Pennsylvania Electric Company*, 58 FERC ¶ 61,278, 62,871–75, *reh'g denied*, 60 FERC ¶ 61,034 (1992), *aff'd sub nom. Pennsylvania Electric Co.* v. *FERC*, 11 F.3d 207 (D.C. Cir. 1993); *see also Entergy Services, Inc.*, 71 FERC ¶ 61,139, 61,452 (1995) (regarding the pricing of redispatch service, the Commission stated ''[i]t is a well-settled matter that the Commission will not authorize ''and'' pricing, *i.e.*, embedded cost pricing plus opportunity (incremental) cost pricing.'').

[642] Order No. 888A at 30,267.

[643] *Florida Power & Light Co.*, 70 FERC ¶ 61,158 at 61,483 (1995).

[644] *E.g.*, Nevada Companies, Community Power Alliance, Progress Energy, LPPC, Southern, WAPA, and APPA.

[645] *E.g.*, E.ON, Ameren, and APPA.

1033. Other commenters argue that violations of the Standards of Conduct can be avoided by various means. PPM suggests that publication of redispatch costs similar to ancillary service costs and elimination of case-by-case sharing of information between the transmission provider and the generation operators would avoid Standards of Conduct issues. MidAmerican states that sole reliance upon bilateral agreements with third parties to provide planning redispatch would resolve the need to modify the Standards of Conduct. In their reply comments, Utah Municipals state that they do not believe the Standards of Conduct pose a barrier to provision of planning redispatch since transmission providers redispatch to serve their own loads currently, but that if so the Commission should make small modifications to the standards.

Commission Determination

1034. The Commission does not believe that any changes to its Standards of Conduct are required for transmission providers to implement the planning redispatch provisions adopted in this Final Rule. The information at issue, *e.g.*, generation redispatch cost, is held by the marketing affiliate and there is no prohibition under our Standards of Conduct on the marketing affiliate transferring such information to the transmission provider. The information sharing prohibitions under the Standards of Conduct are ''one way,'' *i.e.*, they restrict only communications of non-public transmission information from the transmission provider to the marketing affiliate, not vice versa. Therefore, the flow of information from marketing affiliates to transmission providers relating to the costs and availability of generation resources for planning redispatch is not prohibited under the Commission's Standards of Conduct.[646]

1035. We next turn to the flow of information from the transmission provider to the marketing affiliate. Initially, in order for transmission providers to evaluate planning redispatch options, they must identify the impacted transmission facilities, *e.g.*, flowgates, and determine the marketing affiliate's generators that could provide redispatch over those facilities. Transmission providers already have this information to enable them to provide least cost reliability redispatch. However, transmission providers need not provide information regarding the impacted transmission facilities to its marketing affiliates. Rather, in order for transmission providers to evaluate the future availability of redispatch and estimate the costs of redispatch, they need only tell the marketing affiliate which of its generators would be suitable for redispatch, thus identifying those that require study. This sharing of information relating to the marketing affiliate's generation is not prohibited by the Commission's Standards of Conduct.

1036. In addition, the transmission provider may also need to provide its marketing affiliate with transmission-related information from the transmission customer's service request, such as service quantity and term, to determine the required duration and amount of the redispatch required. We find that such information provided from the transmission provider to the marketing affiliate is not a prohibited transfer of non-public information because such details of the transmission customer's service request are available via OASIS. The only customer transmission request information not readily available via OASIS is the source and sink information.[647] We see no need for the transmission provider to provide such masked source and sink transmission information to its marketing affiliate as part of this redispatch evaluation process. We do not believe that any further information need be provided by the transmission provider to their marketing affiliates to evaluate the generators available for planning redispatch and their costs. Accordingly, we find there is no need to create an exception to the Standards of Conduct for the sharing of this generation-related information and publicly available transmission customer request information.

(E) Attributes of Conditional Firm

NOPR Proposal

1037. In the NOPR, the Commission described conditional firm service as a modified form of point-to-point service that includes non-firm service in a defined number of hours of the year when firm point-to-point service is not available. The Commission proposed that the conditional firm service agreement would identify the conditional curtailment hours and include an annual or monthly cap on those hours. The Commission further proposed that conditional firm service would be curtailed before firm uses until such times as the conditional curtailment hours were exceeded, after which time the service would be treated as firm. The curtailment priority during the conditional period was proposed as the same as secondary network service. The Commission proposed that customers using the conditional firm option would pay the long-term firm point-to-point rate. The Commission also proposed that conditional firm service qualify for rollover rights, provided that it meets the other rollover right conditions proposed in the Final Rule.

(i) General Terms and Conditions

Comments

1038. Most commenters support pricing conditional firm service at the long-term firm OATT rate and no commenter suggested a different pricing method. Nevada Companies and Bonneville state that the customer seeking conditional firm service should pay the actual costs of the study required to provide the number of conditional curtailment hours.

1039. EPSA and AWEA support the following components of the Commission's conditional firm proposal: Conditional firm is available only to customers that first request long-term service; it would provide a year round, long-term product that is firm during all hours of the year except at well-defined periods when the transmission provider is unable to provide the service; and, in all hours that are not conditional, conditional firm service would be treated as any other firm service with the same curtailment priority as long-term firm network and point-to-point rights.

1040. EEI proposes that conditional firm service be firm in periods when firm service is available according to ATC calculations and non-firm, with a monthly non-firm curtailment priority, for periods when firm ATC is not available. CREPC, Exelon and MidAmerican argue that the Commission should not require conditional firm service until all attributes of the service are clearly defined and key implementation issues are resolved, including modification of NAESB and NERC processes. NAESB states that the Commission can reduce the amount of time required to develop OASIS and transmission loading relief protocols by clearly defining the conditional firm service.

1041. In its supplemental comments, EEI states that the Commission should not require all transmission providers to adopt terms and conditions for conditional firm service that are only workable for some systems, *e.g.*, transmission providers in the Western Interconnection using the rated path

[646] 18 CFR 358.5.

[647] *See Open-Access Same-Time Information System and Standards of Conduct*, 83 FERC ¶ 61,360 at 62,456 (1998), *reh'g denied*, 86 FERC ¶ 61,139, *reh'g denied*, 87 FERC ¶ 61,382 (1999).

methodology compared to many in the Eastern Interconnection using a flow-based methodology; rather, the Commission should allow flexibility in the offer of conditional firm service so that transmission providers are not foreclosed from offering the service.

1042. Several commenters state that transmission providers and customers collectively should design the conditional firm service that best accommodates their respective needs.[648] In supplemental comments, Bonneville states that the transmission provider, not the customer, must determine the conditions to offer in response to a given request. Bonneville also requests that the Commission clarify that there would be no separate queue for conditional firm service.

Commission Determination

1043. The Commission adopts the conditional firm option as a modified form of long-term firm point-to-point service that includes less-than-firm service in a defined number of hours of the year or during defined system conditions when firm point-to-point service is not available. The service can be curtailed solely for reliability reasons during the defined system conditions or defined number of hours. We reject EEI's suggestion to use a monthly non-firm curtailment because it would allow for curtailment of the conditional service for economic reasons.

1044. In this Final Rule, we define the minimum attributes of the conditional firm option rather than allow individual transmission providers to develop any form of service that could conceivably be labeled conditional firm service. The Commission has been considering a conditional firm product and has been discussing it with the industry for some time. In early 2005, the Commission held a technical workshop to:

> Work with market participants to develop clear definitions for additional wholesale electric transmission services, *e.g.*, conditional firm transmission service, develop applicable pro forma tariff language that could be included in public utilities' open access transmission tariffs and address attendant issues.[649]

Although commenters in that proceeding stated that the Commission need not require new services in transmission providers' OATTs because they would be voluntarily developed,[650] no individual transmission provider developed new services in response to the workshop. In fact, seemingly, only one transmission provider in the Eastern or Western Interconnection offers a service that is similar to the conditional firm service adopted in this Final Rule.[651]

1045. Since the issuance of the NOPR, the Commission has provided the industry with three formal opportunities to provide comments on implementation of the conditional firm option. The Commission held a technical conference on implementation issues after issuance of the NOPR and held many informal technical discussions with industry representatives. We have taken these steps in order to make the most reasoned decision concerning the minimum attributes of the conditional firm option. These conferences and workshops have been helpful and have informed our decision on the minimum attributes of conditional firm service. As noted herein, although we are establishing certain minimum attributes, we also allow for some measure of flexibility in provision of the service. We will not, however, approve conditional firm as a concept only. Given our past experience, this would provide little benefit to customers seeking to use the service and no certainty to transmission providers seeking to comply with our regulations.

1046. Further, as discussed in more detail below, we disagree that NERC must modify its processes in order to allow transmission providers to implement this product. However, we will allow for a sufficient period of time for development of business practices and tracking mechanisms to implement the product. We recognize that there may be some regional variation in the way transmission providers approach the provision of conditional firm service beyond the minimum attributes that we establish in this Final Rule. Thus, we do not direct that transmission providers work with NAESB to develop business practices for implementation of the conditional firm service. Rather, we direct transmission providers located in the same region to coordinate such development among themselves. We also encourage participation of non-public utility transmission providers in the region and interested transmission customers in the development of these business practices. Public utility transmission providers should make efforts to include these interested parties in their regional coordination efforts. We direct transmission providers to implement these mechanisms and business practices within 180 days after the publication of this Final Rule in the **Federal Register**.

1047. The Commission adopts the proposal in the NOPR that customers using the conditional firm service pay the long-term firm point-to-point rate. We will not allow complete flexibility in defining the conditional firm option as suggested by EEI because such an option could provide a substantially lower quality service for which transmission providers would be able to recover the long-term firm rate. We also reject EEI's proposal that the service be a mix of firm and non-firm periods. We envision the conditional firm option as one in which firm service is available most of the period of a year. EEI seems concerned about tailoring the product to situations where congestion is so acute that the ''conditions'' require frequent interruptions. We do not believe this concern is well founded. Because a conditional firm customer is obligated to pay the long-term firm point-to-point rate, we assume that few, if any, customers would accept the service in circumstances where the interruptions (or ''conditions'') are so frequent or pervasive to make the service unattractive.

1048. Finally, we clarify for Bonneville that customers seeking the conditional firm option must first request long-term firm service. When ATC is unavailable, the transmission provider must study the conditional firm option at the customer's request. There is no separate queue for the conditional firm option.

(ii) Specified System Conditions and Conditional Hours

Comments

1049. Several transmission providers state that they cannot accurately predict the conditional curtailment hours because there are too many variables to consider and ATC analysis does not provide this level of granularity.[652] These commenters contend that load flow modeling for a wide range of

[648] *E.g.*, LPPC Supplemental, PPL Supplemental, Williams Supplemental, Community Power Alliance Supplemental, Entergy Supplemental, and Southern Supplemental.

[649] Potential New Wholesale Transmission Services, Notice of Final Agenda for Technical Workshop, 70 FR 12865 (Mar. 16, 2005).

[650] *E.g.*, Bonneville Workshop Comments at 1–2 (April 13, 2005) (stating that Bonneville believes the result of the workshop ''will be the development of one or more new transmission products.''), TAPS Workshop Comments at 2 (April 13, 2005) (suggesting that the Commission should invite and consider proposals by individual utilities rather than act by rulemaking).

[651] In the NOPR, the Commission noted PacifiCorp's 2002 modifications to partial interim service. *See* NOPR at P 319 n.298. PacifiCorp's service is similar to that proposed by EEI with the exception that customers are charged a pro rated long-term firm rate.

[652] *E.g.*, Imperial, Duke, Progress Energy, MidAmerican, PNM–TNMP, Southern, and EEI.

possible system conditions required to estimate the conditional curtailment hours would be complex, time-consuming and costly. Given this concern, Southern, PNM–TNMP, and MidAmerican state that any conditional firm service should be subject to a ''reasonable efforts'' standard and not represent a guarantee of service or a binding estimate of conditional curtailment hours from the transmission provider. Progress Energy states that it would be difficult to determine a specific number of hours that firm service is available, given that the industry uses seasonal models. Ameren states that the conditional curtailment hours should be spelled out in the transmission service agreement.

1050. Several commenters state that the transmission provider should provide customers a choice between defined system conditions and conditional curtailment hours.[653] In supplemental comments, EPSA and AWEA state that neither option should be arbitrarily excluded; rather, they argue that transmission providers should consult with each customer in determining the defined conditions that could form the basis of the conditional firm service. EPSA and AWEA propose that conditional firm should be firm during all hours of the year except in those hours in which a defined contingency occurs, and the transmission provider is actually unable to provide service. EPSA and AWEA also propose that the system impact study should describe the reliability contingency and the transmission service agreement should clearly define the contingency.

1051. EPSA and AWEA state that conditional firm should only be curtailed after all non-firm services are curtailed on the same constrained path during the period of the defined contingency. Finally, AWEA and EPSA state that transmission providers must maintain the committed capacity subject to the defined contingency only, reflect capacity commitments for conditional firm service in their ATC calculations, and be prevented from further curtailing conditional firm service due to load growth after the execution of the initial service agreement.

1052. AWEA proposes that if a service agreement specifies conditional curtailment hours, the transmission provider must provide firm service except in the curtailable hours defined in the service agreement and the service must be treated as firm unless the transmission provider is actually required to curtail transactions to meet reliability requirements and all non-firm transactions have been curtailed. Once the transmission provider has reached the annual cap on curtailable hours, AWEA argues the customer's service should convert to traditional firm service for the remainder of that annual period.

1053. Utah Municipals reply that transmission providers should be bound by their calculations of the availability of firm service, even if the firm service is not available year-round.

1054. FirstEnergy and Nevada Companies state that monthly caps, as opposed to annual caps of curtailment hours, would be preferable because they provide more information to the customer and are more appropriate for transmission systems with mostly seasonal constraints. According to Nevada Companies, a curtailment based upon the maximum number of hours per year, without taking into account the specific times or conditions for those curtailments, would be unworkable in the context of a seasonal peak system, such as exists with Nevada Companies.

1055. Several commenters support a variation on conditional firm service that would allow a transmission provider to specify either the transmission facilities/elements that may become constrained or the operating conditions that will result in curtailments of a particular conditional firm service.[654] Many of these commenters propose a defined system condition as the trigger for non-firm curtailment of the service rather than the use of conditional curtailment hours.[655] Entergy and LPPC propose that such curtailments have the same priority as secondary network service. Entergy contends that this service would be superior to the conditional firm service described in the NOPR because it would be more comparable with the service transmission providers make available to network customers and would minimize the risk to other customers who might otherwise bear the cost of inaccurate conditional curtailment hours, as well as disputes between the transmission provider and the transmission customer regarding the number of conditional curtailment hours. Seattle and Santee Cooper suggest that defining the limitations on the service based on operating conditions, with non-binding estimates of hours of curtailment, would lead to more effective and reliable operation of the transmission system that is consistent with regional requirements.

1056. In supplemental comments, Bonneville asserts that the transmission provider should have the option of offering conditional curtailment hours or specified system conditions in order that the transmission provider can make a prudent choice based on available historical system data.

1057. In supplemental comments, TAPS argues that conditional firm service should be limited to 100 hours per year of conditional curtailment, subject to curtailment on the same basis as firm service beyond those hours, and made available to and integrated with network customers. In TAPS view, this would result in a more efficient use of the grid, provide customers sufficient certainty to sign long-term power purchase contracts and promote transmission construction. TAPS also believes that the customer should have the option of expressing the curtailment restriction on the basis of specified system conditions in the 100-hour range.

1058. In its supplemental comments, Entergy suggests that the Commission allow more flexibility between the contracting parties to identify the conditional nature of the service, *i.e.*, the Commission should not prescribe parameters of the conditional period that may ignore real-time conditions on the transmission provider's system that require a curtailment.

1059. EEI, Duke, and PNM–TNMP object, in their supplemental comments, to specifying system conditions or the maximum number of curtailment hours per year, stating that requiring either would be incompatible with current curtailment procedures and unfairly shift risks of curtailment to other firm customers. EEI, Progress Energy and Duke argue that the service should be curtailable during a particular season, month or other defined period to provide more certainty to the transmission customer and the transmission provider as to when the service is subject to curtailment.

1060. With regard to modeling methods for estimating the conditional curtailment hours, EEI asks the Commission not to require the transmission provider to use a specific methodology to evaluate whether it can provide conditional firm service. Bonneville argues that transmission providers need flexibility to modify their ATC methodologies to appropriately model the new service and avoid planning obligations to firm

[653] *E.g.*, Barrick Supplemental, Bonneville Supplemental, BP Energy Supplemental, and EPSA and AWEA Supplemental.

[654] *E.g.*, AWEA, EPSA, Project for Sustainable FERC Energy Policy, Santee Cooper, Seattle, Entergy, and LPPC.

[655] *E.g.*, Santee Cooper, Seattle, Entergy, LPPC, and Nevada Supplemental.

up the conditional curtailment hours of a conditional firm reservation. Nevada Companies suggest that the transmission provider use the appropriate seasonal operating case with updated projections to determine the amount of requested service that can be provided without violating reliability criteria.

1061. Ameren argues that when a transmission provider models system contingency events, the events are not interchangeable with a number of hours. According to Ameren, the two measurements will produce different impacts for the transmission system, and the transmission provider should not be required to make both options available at the customer's option. LPPC and Public Power Council state that transmission providers should not be required to limit the number of curtailments on a monthly or yearly basis because of the inherent unpredictability of future transmission constraints. APPA states that using curtailment based on a specified number of hours will cause the transmission provider to overestimate the number of curtailment hours.

1062. NRECA believes that the Commission should allow for regional flexibility in the determination of the parameters of the service and transmission providers should have maximum flexibility to set conditions that use conservative assumptions (*e.g.*, based on the driest weeks of the year, summer or winter peak period constraints). NRECA believes such service should be conditioned on operating conditions as well as with reference to a number of times of interruption. In contrast, MISO supports the election of a consistent method of curtailment applied to all customers, in order to make the service easier to implement.

1063. Powerex states that conditional firm service should be offered only on paths where curtailment to existing long-term customers is not expected to occur.

Commission Determination

1064. The Commission requires that, when conducting the system impact study for the conditional firm option, the transmission provider shall identify: (1) The specific system condition(s) when conditional curtailment may apply; and (2) the annual number of hours when conditional curtailment may apply. A customer must select either conditions or hours for incorporation into its conditional firm service agreement.

1065. We require the offer of specific system conditions during which conditional curtailment may apply for several reasons. Specified system conditions give certainty to the customer that it will only be conditionally curtailed when forecasted reliability problems actually occur. Transmission providers benefit from this option because they can point to specific constraints on their system and implement a curtailment plan when those transmission elements are constrained. Additionally, designation of specific system conditions may allow for a better fit of the conditional firm service to a specific transmission provider's system. Consider the example of firm service that is not available on a specific system because a transmission line is taken out of service for maintenance about two weeks a year. The designation of this line as the specific condition for conditional firm service would allow the transmission provider to provide firm service without having to worry if the maintenance on the line takes an extra week. The conditional firm customer has fewer concerns about undue discrimination by the transmission provider and could benefit from maintenance on the line that was finished one week early. Additionally, we note that many commenters representing transmission providers and customers support this approach.

1066. We will require specificity of system conditions. Acceptable system conditions include, but are not limited to, designation of limiting transmission elements, such as a transmission line, substation or flowgate. We do not believe, however, that designation of system load levels, standing alone, would qualify as an acceptable system condition. Rather, load levels would have to be linked to a specific constraint or transmission element that is associated with the request for service, *e.g.*, load levels in a constrained load pocket. Otherwise, the system load level would not be specific to the part of the system over which service is requested and, hence, have no necessary relation to the problems, if any, created by the service being requested. Furthermore, because most system loads experience load growth every year, conditional curtailments would necessarily increase over a multi-year conditional firm service term.

1067. We recognize that modeling of the conditional curtailment hours entails difficulties beyond those encountered in modeling ATC. To address these difficulties we are allowing flexibility in determining the number of hours. We clarify that we will not require a standardized method of modeling the conditional curtailment hours. We also note that the Commission's examination of modeling methods in the NOPR was not meant to propose one method over another; rather, it was meant to examine possible ways to determine a number of conditional curtailment hours to encourage dialog on the issue. Additionally, we will allow transmission providers to add a risk factor to their calculation of annual curtailment hours to account for forecasting risks. Further, we note that our adoption of the conditional bridge and reassessment products, detailed above, address modeling difficulties by limiting the number of years that a transmission provider must model in determining both the number of hours and future system conditions. Moreover, we clarify that if the customer selects the annual hourly cap option, the transmission provider has the flexibility to conditionally curtail the customer for any reliability reason during those hours, including but not limited to, the system condition(s) identified in the system impact study. Without this flexibility the hourly cap option and the specific system condition option would be indistinguishable with a cap on the number of hours that the system conditions interruption could occur.

1068. We will require annual caps on the number of hours because calculating an annual cap entails less risk for the transmission provider and its existing firm customers than monthly or seasonal caps. While we will not require monthly or seasonal caps, we encourage transmission providers to offer them if they can overcome modeling barriers because monthly or seasonal caps give more certainty to customers about the particular aspects of their service. Though we allow for flexibility in modeling and determining the number of conditional curtailment hours for a particular service request, we believe that this will have a minimal impact on conditional firm customers. Transmission providers will be allowed to curtail only for reliability purposes and conditional firm customers during conditional curtailment hours will be curtailed only after all point-to-point non-firm customers have been curtailed.

(iii) Conditional Curtailment Priority

Comments

1069. Some commenters agree with the Commission's proposal that conditional firm service should have secondary network curtailment priority during conditional curtailment hours,[656] while others disagree. Bonneville supports the use of the secondary

[656] *E.g.*, Bonneville, AWEA Reply, and EPSA Reply.

network curtailment priority arguing that customers will value the service more with the secondary network priority, thus increasing the viability of conditional firm service as an alternative to transmission upgrades. EPSA and AWEA argue that conditional firm service during conditional curtailment hours should be curtailed after all non-firm uses. In their reply comments, TDU Systems oppose EPSA and AWEA's position, arguing that secondary network service should have at least as high a priority as conditional firm service. In contrast, EEI argues that setting the curtailment priority equal to secondary network service would adversely impact the reliability of firm service by reducing real-time redispatch options and contradict Order No. 888 precedent that provides priority non-firm service only for network customers that pay a load ratio share of system costs.[657] If conditional firm service is implemented, Powerex states that transmission providers should provide data and evidence demonstrating that the rights of existing long-term firm customers will be protected. EEI takes issue with the Commission's proposal to grant conditional firm customers priority non-firm service during conditional curtailment hours because they would pay for long-term use of the grid, stating that all long-term point-to-point customers pay for service on a long-term basis but, unlike network customers, they do not get priority non-firm service.

1070. Commenters address implementation issues related to the Commission's right of first refusal, tagging, tracking, and curtailment priority proposals, as well as other implementation issues implicated in the conditional firm service. Manitoba Hydro, Bonneville and Seattle support the Commission's proposal that conditional firm service would qualify for right of first refusal when firm service becomes available. Several commenters believe that the Commission's proposal with regard to right of first refusal should be refined to allow automatic assignment to conditional firm customers of firm capacity as it becomes available in the short term.[658] Bonneville asserts that prior to implementation of the new service the industry must work with NAESB to develop a communications protocol to either employ automatic assignment or right of first refusal.

1071. Entergy and Exelon state that the standards for implementing transmission loading relief, including the NERC's Interchange Distribution Calculator (IDC), would need modification to allow for curtailment. Specifically, Entergy contends that the Commission should allow time for the IDC to be modified to specify a different curtailment priority for the same transaction depending on the identity of the constraining element. Imperial states that it may take over a year to develop computer software to correctly handle new curtailment priorities during an emergency. Bonneville disagrees and states that conditional firm service does not present unique issues with respect to curtailment and that it would be curtailable during real time like secondary network service.

1072. EEI states that the conditional firm service as currently proposed would conflict with tagging protocols and NERC criteria because there is currently no way to tag service as both firm and non-firm. EEI states that, if conditional firm service is subject to curtailment during a specific period, the tag can identify those periods and curtailments will be implemented in conditional periods and non-conditional periods in accordance with those tags. However, if conditional service is curtailable in a certain number of hours, or when specific conditions occur, the tag cannot be rewritten in a way that will provide for curtailment without personal involvement of balancing authority operators, which could lead to increased curtailments of firm transmission customers.

1073. Xcel states that limiting curtailments to a specified number of hours per year could result in conditional firm service having greater value than firm, while strictly adhering to a maximum number of curtailment hours could potentially conflict with the reliability standards in section 215 of the FPA. NRECA argues that conditional firm service should be subject to *pro rata* curtailment with all other firm users during non-conditional times.

Commission Determination

1074. We adopt a secondary network curtailment priority to apply for the hours or specific system conditions when conditional firm service is conditional. During non-conditional periods, conditional firm service is subject to *pro rata* curtailment consistent with curtailment of other long-term firm service. Thus, secondary network service and conditional firm service when it is conditional will share the same curtailment priority. Also, there is no conflict with reliability standards because conditional firm service will be subject to *pro rata* curtailment with all other firm uses of the system once conditional curtailment hours, if that is the option selected, are exhausted.

1075. The secondary network curtailment priority is appropriate because the customer is paying the long-term firm point-to-point rate and thus should receive the highest non-firm curtailment priority during the conditional curtailment hours or during specified system conditions. Adoption of this curtailment priority overcomes what could otherwise be significant implementation hurdles. It allows for implementation of the service without changes to existing NERC TLR practices. NERC and members of the industry need not undertake the time-consuming and expensive process of establishing a new curtailment priority that is between firm and non-firm service as some commenters requested. Use of this curtailment priority also avoids attendant decisions relating to the method of curtailment that should apply, *i.e., pro rata* or transactional curtailment, for a quasi-firm curtailment priority. It is also consistent with existing interruption provisions of the *pro forma* OATT which provide that secondary service cannot be interrupted for economic reasons.[659] This is consistent with our determination that conditional firm service when it is conditional is curtailable only to maintain reliable operation of the transmission system.

1076. We reject EEI's argument that the curtailment priority for conditional firm service is inconsistent with Commission precedent regarding priority non-firm service only for network customers. EEI's argument is inapposite. Long-term firm point-to-point customers taking fully firm service without the conditional firm option do not need access to priority non-firm service as EEI suggests. They have assurance that their service will not be interrupted for economic reasons and will only be curtailed on a comparable basis with network service. This would not be the case for conditional firm customers. We also find that EEI has failed to explain the connection between the conditional firm transmission service and the availability of reliability redispatch options, *i.e.*, generators on its system that can ramp up or down in response to a curtailment. We reject Powerex's request that transmission providers be required to show that existing long-term rights are protected. Each addition of a new long-term firm transaction impacts

[657] *Citing* Order No. 888 at 31,750.

[658] *E.g.*, EEI, EPSA, TranServ, Bonneville, Constellation and Seattle Reply.

[659] *See pro forma* OATT section 14.7.

the rights of existing firm customers to some extent.

1077. We disagree with commenters' suggestion that the NERC IDC must be changed to accommodate conditional firm service. We reiterate that we are not creating a new curtailment priority in this Final Rule. We also disagree that new tags that combine a firm and non-firm priority must be developed in order to implement the conditional firm option. The curtailment priority in a tag can be changed ahead of the operating hour based on a near-term forecast of system conditions.[660] We are cognizant that daily and hourly operations to change the tags for conditional firm customers likely involve the need for control room coordination and development of an appropriate tracking process. As the Commission described in the NOPR, new tracking and tagging business practices for this service must be developed by each transmission provider. Thus, we are allowing a sufficient period for the development of these business practices, *i.e.*, 180 days from the date of publication of this Final Rule in the **Federal Register**. As directed above, transmission providers must coordinate with other transmission providers in their regions to develop these tracking and tagging business practices.

1078. Finally, we address requests to allow for automatic assignment of short-term firm point-to-point service to conditional firm customers. We agree that transmission providers must take into account the conditional firm service in evaluating the availability of short-term firm service. Because conditional firm is a long-term firm use of the system, it should not be interrupted prior to short-term firm service. However, short-term firm service reserved prior to the reservation of conditional firm service should maintain priority over conditional firm service in the periods when conditional firm service is conditional, *i.e.*, when specified system conditions exist or conditional curtailment hours apply. Because the assignment proposal meets both of these objectives, we direct transmission providers to assign short-term firm service to conditional firm customers as the service becomes available. Accordingly, we direct transmission providers to work with NAESB to develop the appropriate communications protocols to implement this attribute of conditional firm service. Transmission providers need not implement this requirement until NAESB develops appropriate communications protocols.

(iv) Rollover Rights

Comments

1079. Several commenters support the Commission's proposal that conditional firm service would qualify for rollover rights.[661] Manitoba Hydro, Bonneville and Seattle state that rollover rights are appropriate where the transmission provider does not have an obligation to plan for service to the conditional firm customer during the conditional curtailment hours. Bonneville adds that, in rolling over conditional firm service, the transmission service agreement should allow for no more than the same number of conditional curtailment hours than in the original service agreement and provide for fewer hours of curtailment if system conditions provide for more firm service. If conditional firm service is used as an interim product until transmission is built, APPA contends that rollover rights would be appropriate.

1080. Others argue that rollover rights for conditional firm service are inappropriate.[662] These commenters do not support the granting of rollover rights, nor do they support the designation of conditional firm service as long-term service. In order to accommodate conditional firm rollover rights, FirstEnergy contends that the transmission provider would be required to model a number of off-peak load flow cases and provide system reinforcements. Ameren states that the number of hours that the service will be available at some future date after the contract expires will not be known at the time the initial contract is executed. EEI adds that estimating conditional curtailment hours for 10 years of service is an impossible task. MISO states that rollover rights would add more complexity to the AFC/ATC calculation process and competition queues. Entergy and EEI state that, while subsequent firm transmission service should not be placed ahead of the conditional firm service, it is appropriate at the time of a rollover request, and perhaps more frequently, to allow the transmission provider to update the conditional firm service parameters in order to take into account load growth and changes in load for prior services.

Commission Determination

1081. The Commission finds that rollover rights are appropriate for point-to-point service that is provided using planning redispatch or conditional firm options and would otherwise be eligible for rollover rights. The following discussion addresses only rollover rights for service that is paired with a transmission provider's biennial reassessment right. While the Commission agrees with commenters that subsequent firm transmission service requests should not be placed ahead of the conditional firm service, we note above our concerns with the modeling requirements and reliability impacts of an ongoing service that relies upon unchanging curtailment conditions or redispatch requirements. The biennial assessment right, discussed above, addresses the concern expressed by EEI that transmission providers cannot accurately determine conditional curtailment hours or estimate redispatch costs for a ten-year service. The biennial review in conjunction with rollover rights allows the transmission provider to update the parameters of the service in order to maintain reliable operations and allows customers to keep their place in the queue ahead of other customers seeking conditional firm, planning redispatch options, or other firm services.

1082. Rollover rights for the reassessment product can provide significant value to the conditional firm customer. A conditional firm customer opting to roll over will retain priority claim to the portion of its service that is firm. For example, if a five-year conditional firm service initially has a 100-hour annual cap on curtailments, but the cap is later reassessed at 150 hours, the rollover right would continue to give the customer first call on all but the 150 hours as against all other subsequent requests for firm service.

1083. We note that a customer taking conditional firm or planning redispatch options as part of a five-year point-to-point service must declare its intent to roll the service over in the fourth year of service, coincident with the second biennial review. Thus, we task transmission providers and customers, in negotiating their service agreement, with coordinating the timing of the biennial review with the deadline for declaring rollover intent. Specifically, customers deciding whether to renew their service should have information on additional conditions on the service or additional estimated redispatch costs

[660] For example, in the Eastern Interconnection, tags can be changed up to 35 minutes before the hour in which a TLR event is scheduled. *See* NERC Standard IRO–006–3, *Transmission Loading Relief Procedures—Eastern Interconnection*, section 6.2 (Communications and Timing Requirements) at 23–25 (August 2, 2006).

[661] *E.g.*, AWEA, EPSA, Manitoba Hydro, Bonneville, TranServ, Seattle, and Utah Municipals Reply.

[662] *E.g.*, EEI, FirstEnergy, Ameren, SPP, and TDU Systems Reply.

at least 30 days prior to the relevant rollover deadline.

1084. Additionally, because the biennial review provides the transmission provider with the ability to plan for and maintain system reliability, we will not allow the rollover right to infringe upon this review. Thus, we direct that the transmission provider has a right to review the conditions or redispatch requirements at the end of the first year of a service that has been rolled over, *i.e.*, year six of service, as consistent with a biennial review of service.[663]

(v) Use of Conditional Firm Options in Designating Network Resources

Comments

1085. Several commenters state that the Commission should not modify current OATT requirements for designating network resources to include resources delivered using conditional firm service; otherwise, reliability would be threatened because network customers could lean on the system during conditional periods.[664] They oppose allowing a resource taking conditional firm service to qualify as a network resource when the associated resource is imported by a network customer from an adjacent system. EEI and Duke agree with the Commission's NOPR proposal that conditional firm service should not be available to network customers and further assert that a product that includes a non-firm portion is inappropriate for a load-following service like network service. EEI asserts that because the Commission requires that network resources be deliverable on a non-curtailable basis, resources using conditional firm service cannot be designated as a network resource until the maximum conditional curtailment hours have been reached. EEI and Duke contend that establishing a defined period of curtailment for conditional firm service, either seasonal, monthly, or specific dates, eliminates issues with respect to the designation of network resources because a resource using conditional firm service would be eligible for designation for the part of the year when the service was defined as firm. In its reply comments, Duke states that it cannot reliably operate its system if it is required to serve unplanned load when a network resource is undeliverable due to curtailment of conditional firm service.

1086. Other commenters assert that the Commission should create an exception to allow designation of network resources that use conditional firm service.[665] AWEA adds that resources should not lose their designation when transactions are curtailed pursuant to conditional firm service because this is not the way similar resources with special protection systems are treated. Several commenters state that conditional firm service should qualify as a network resource when the associated resource is imported by a network customer.[666] BP Energy adds that more coordination between the two systems with respect to specifying the set of conditions or specific set of hours is required.

1087. Some commenters state that conditional firm service should be made available to network customers because conditional firm service may trump the provision or scheduling of secondary network service and because network customers should have service that is at a minimum equivalent with point-to-point service.[667] These commenters suggest that the Commission could permit network customers to designate a conditional network resource that would be a firm resource for the hours when a comparable conditional firm point-to-point service is firm. In supplemental comments, NRECA and TAPS argue that ''on-system'' LSEs should be allowed to designate a network resource where transmission is fully firm for all but the limited time each year, *e.g.*, to 100 hours or less, and ''off-system'' LSEs should be allowed to treat a network resource supported by conditional firm service as a resource on the host system where it takes network service. NRECA believes that if the criteria for both network service resource designations and for the proposed conditional firm service are based on the physical, engineering characteristics of the transmission system, the network customer should be able to designate the resource as deliverable to load on a non-curtailable basis, except for the specified conditions.

1088. In its reply comments, Bonneville states that since secondary network service cannot be purchased on a long-term basis, the Commission should evaluate whether the design and implementation challenges of creating a conditional firm service for network customers can be overcome. Bonneville also states that other options such as seasonal firm and long-term reservation of secondary network service should be explored in order to allow network customers similar access to monthly ATC.

1089. Nevada Companies state that network customers have load service obligations and should always have unconditional firm service, without exception. However, Nevada Companies state that network customers could benefit from a service similar to conditional firm service. According to Nevada Companies, if a network customer desires to deliver its resources to a point of receipt that is not available all seasons of the year, it could procure firm transmission capacity that is available on a seasonal basis for the delivery of a network resource.

1090. Some commenters state that network customers should be permitted to designate as network resources third party power supplies that are supported by the supplier's conditional firm reservation.[668] In supplemental comments, Xcel states that it does not oppose allowing conditional firm to qualify as a network resource, but it should be clear that the service is an exception to the otherwise ''firm is firm'' policy that requires all firm users to be curtailed pro-rata.

Commission Determination

1091. The Commission will allow conditional firm point-to-point service to qualify as firm service that supports the designation of network resources imported from other control areas. As we explain in more detail in section V.D.6, the Commission has longstanding limitations on network resources. Network resources cannot be interrupted for economic reasons and third-party transmission arrangements to deliver the resource to the network must be non-interruptible.[669] EEI is incorrect that, under our precedent, a resource must be ''noncurtailable'' to qualify as a network resource under the OATT. All resources are ''curtailable''—*e.g.*, if a unit trips off line, the resource is, by definition, curtailed. Network resources may also be unavailable due to other reasons besides an unplanned unit outage, such as unplanned transmission outages or environmental restrictions. It is appropriate to allow conditional firm service to support the

[663] Such a review would occur in the first year of a rolled over service if the initial service term was for five years.

[664] *E.g.*, Entergy Supplemental, Southern Supplemental, MISO Supplemental, Community Power Alliance Supplemental, and Powerex Supplemental.

[665] *E.g.*, AWEA, EPSA, TAPS, APPA, Utah Municipals Reply, and Barrick Reply.

[666] *E.g.*, Bonneville Supplemental, TDU Systems Supplemental, PPL Supplemental, and BP Energy Supplemental.

[667] *E.g.*, NRECA, TDU Systems, TAPS, and Utah Municipals Reply.

[668] *E.g.*, APPA Supplemental, EPSA and AWEA Supplemental.

[669] *Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.*, 84 FERC ¶ 61,120 at 61,660 (1998) (*WPPI*).

designation of network resources because the conditional firm option only affects the transmission of the resource to the network, not the interruptibility of the generating resource itself. Conditional firm service satisfies the Commission's requirement for the delivery of the resource to the network to be non-interruptible because such transmission service is curtailable only for specific reliability reasons, not economic reasons.

1092. We decline, however, to adopt the conditional firm option for network service. Commenters argue that conditional firm network service should be made available to prevent conditional firm point-to-point service from ''trumping'' the scheduling of secondary network service and to ensure that network service is at a minimum equivalent to point-to-point service. Concerns regarding conditional firm point-to-point service ''trumping'' secondary network service would not be resolved by creating conditional firm network service. The ''as available'' nature of secondary network service will still permit all firm uses of the system, including conditional firm service, to have a higher reservation priority than secondary network service. Creating a conditional firm network service would not change that reservation priority.

1093. Others argue that conditional firm network service should be required in order to ensure that network service is equivalent to point-to-point service. As noted above, however, the two services are not precisely the same, nor were they intended to be identical. In Order No. 888, the Commission attempted to strike a balance between competing interests in designing network and point-to-point transmission services, each service with its own costs and benefits. It is therefore appropriate that we consider the need for conditional firm service in each context. While we conclude that implementation of conditional firm network service is not necessary to remedy undue discrimination at this time, we note that allowing conditional firm point-to-point service will nonetheless provide substantial benefits to network customers by allowing the designation of network resources delivered to the network from other control areas using conditional firm point-to-point service. Conditional firm point-to-point service will thereby allow network customers to access new alternative power sources. Transmission providers are free to make a filing under FPA section 205 proposing conditional firm network service.

1094. Finally, in light of our conclusions above that conditional firm service satisfies the Commission's requirements for designating network resources because the delivery of the resource to the network is not interruptible for economic reasons, we do not need to adopt a seasonal, monthly or periodic method for determining the conditions under which conditional service may be curtailed as suggested by EEI and others.

b. Proposals for Transparent Redispatch

NOPR Proposal

1095. In the NOPR, the Commission explained that the major focus of this rulemaking was to strengthen the *pro forma* OATT in order to remedy undue discrimination rather than create new market structures. The Commission stated its intention to retain the use of an OATT to facilitate the development of competitive wholesale markets by reducing barriers to entry through the control of transmission assets, not impose any particular market structure on the industry.

Comments

1096. Several commenters argue that the Commission should expand the planning redispatch requirements of the *pro forma* OATT to incorporate third party provision of redispatch and bidding protocols.[670] In reply comments, Transparent Dispatch Advocates submitted a proposal that, among other things, would require transmission providers to (1) post the real-time cost estimate of providing redispatch service from their resources at congested locations, (2) accept offers from third parties to provide redispatch service, and (3) provide real-time redispatch to resolve transmission constraints. Transparent Dispatch Advocates argue that their proposal is consistent with the scope of the rulemaking because it would not require the adoption of LMP markets or other standardization; rather, it would simply provide cost visibility and proper cost assignment of the dispatch decisions made by transmission providers.

1097. In a notice issued on November 15, 2006, the Commission sought further comment on the TDA proposal. The Commission asked, inter alia, about implementation impediments and confidentiality issues related to posting redispatch costs, whether the TDA proposal was required to remedy undue discrimination, and whether third party participation in redispatch would require market mechanisms.

Commission Determination

1098. The Commission addresses below two distinct parts of the TDA proposal: (1) Expansion of transmission provider's real-time reliability redispatch obligation as well as inclusion of third-party resources in provision of redispatch and (2) posting of real-time redispatch costs or prices.[671] The Commission has carefully considered both the TDA proposal and the comments respecting it. We agree with many of the public policy goals articulated by Transparent Dispatch Advocates, such as increasing the transparency of information and increasing the efficient use of existing infrastructure. However, we also agree with many of the commenters that certain aspects of the TDA proposal are unclear and, depending on its interpretation, may require the creation of new services under the *pro forma* OATT or new market structures. We are particularly cognizant of the arguments of customer groups such as APPA, NRECA and TAPS that the TDA proposal may be difficult to implement, contentious, and may not provide significant benefits to customers. These customers also are concerned that it may detract from other reforms considered in this proceeding that they believe provide greater benefits, such as transmission planning reform.

1099. After considering the views of all the parties, the Commission has sought to strike a reasonable balance between the positions of the commenters. On the one hand, we adopt certain reforms that will provide additional information regarding redispatch costs in a manner that benefits consumers. On the other hand, we will not adopt the portions of the TDA proposal that would require the creation of new services under the *pro forma* OATT or new market structures. We do not believe that such fundamental changes are necessary or appropriate at this time, nor do we have an adequate record upon which to adopt them.

1100. Specifically, the Commission declines to adopt the TDA proposal to expand transmission providers' real-time reliability redispatch obligations and incorporate third party bids into redispatch. As discussed in detail above, transmission providers will continue to have an obligation to

[670] *See* section V.C.1 of this Final Rule for a discussion of comments regarding independent dispatch and spot market development.

[671] Transparent Dispatch Advocates' proposal for mandatory coordination agreements between transmission providers for provision of redispatch service is addressed in section V.C.1 of this Final Rule.

perform reliability redispatch for network customers and provide the planning redispatch described above for point-to-point customers. Transmission providers will not be required, as Transparent Dispatch Advocates request, to incorporate third party resources when providing reliability redispatch or evaluating planning redispatch options for point-to-point or network transmission service. We will, however, institute a posting requirement so that the actual costs of redispatch under existing and future redispatch agreements is made transparent to potential customers. While we will not require posting of a real-time estimate of redispatch prices as proposed by Transparent Dispatch Advocates, the Commission concludes that the posting requirement required herein will provide important information regarding the costs of redispatch without revealing confidential information that might harm existing markets.

(1) Expansion of Reliability Redispatch Obligation and Inclusion of Third Party Resources

Comments

1101. In reply comments filed September 20, 2006, Transparent Dispatch Advocates argue that the Commission must bring transparency to the dispatch function to make redispatch effective and fair and to thereby remedy the potential for discriminatory provision of transmission service. Transparent Dispatch Advocates assert that the Commission should require each transmission provider to publish a ''dynamic real-time value of what it would charge to provide redispatch service at specified congestion locations within the transmission provider's system and at specified flowgates at the border of the transmission provider's system.'' [672] Transparent Dispatch Advocates contend that the publication of this data would: Allow customers to assess available real-time redispatch options; allow customers to access redispatch at actual costs; allow customers to predict with reasonable certainty the costs of redispatch; allow all resource owners to voluntarily offer redispatch solutions and be properly compensated for their efforts; and over time, support long-term transmission service.

1102. In reply comments, Transparent Dispatch Advocates further request adoption of rules that would either require the transmission provider to account for independent, third party resources in its control area in establishing redispatch costs, or allow independent resources to post real-time, cost-based price and quantity bids for redispatch plus the resource's impact on the constraint on the transmission provider's OASIS. Transparent Dispatch Advocates state that the published redispatch values would be cost-based in non-market environments.

1103. On November 3, 2006, a summary of, and frequently asked questions regarding, the TDA proposal (TDA Summary) was attached to comments filed by San Diego G&E in response to the October 12 Technical Conference and in support of the TDA proposal. In the TDA Summary, Transparent Dispatch Advocates assert that the Commission need only revise the existing redispatch provisions of the *pro forma* OATT to require posting by the transmission providers of the nature of congestion at pre-designated flowgates and data concerning the response required to relieve congestion. Additionally, the TDA Summary states that the transmission provider would have no obligation to provide for real-time redispatch from its own or affiliated generation; rather, all generators wishing to provide redispatch could volunteer to submit bids. Transparent Dispatch Advocates state that these bids could be either market or cost based depending on whether the bidder has market-based rates within the control area. The transmission provider would be obligated to evaluate the bids, publish the price for redispatch, and call on generators to provide the requested redispatch in real time. Transparent Dispatch Advocates suggest that transmission providers calculate the price for redispatch by taking the difference between bids received by those generators that the transmission provider would call upon to increase output (*i.e.*, to redispatch) and the costs the transmission provider otherwise would have paid the generator whose output is lowered to relieve the constraint. Transparent Dispatch Advocates contend that their proposal differs from LMP markets because, while LMP sets system-wide clearing prices, their transparent redispatch proposal would apply only at selected flowgates and only with respect to those transacting at those flowgates.

1104. On December 15, 2006, in supplemental comments filed in response to the Commission's November 15 Notice asking for comment on the TDA proposal, Transparent Dispatch Advocates sought to clarify their proposal. Transparent Dispatch Advocates propose that the Commission impose upon transmission providers an obligation to do the following: Provide reliability redispatch to point-to-point customers in real-time for comparable treatment to that currently provided to network customers and native load; consider their own resources, network resources, and offers from non-network resources in providing least cost redispatch in real-time; and, publish real-time information about the cost of redispatch (including the prices submitted by non-network resources) on its OASIS site on a frequent and timely basis. In their supplemental comments, Transparent Dispatch Advocates propose a different method for calculating redispatch prices using the difference between the cost of the generation raised and the pre-redispatch transmission provider's system-wide marginal cost (*e.g.*, system lambda). Transparent Dispatch Advocates further propose that point-to-point redispatch customers taking this service would not be subject to curtailment along with other firm customers in accordance with the current OATT curtailment rules. Transparent Dispatch Advocates argue that their modified proposal would facilitate comparable access to redispatch service and ensure that the existing redispatch provisions of the OATT can be made effective.

1105. Several parties offer comments in support of the TDA redispatch proposal.[673] Constellation encourages the Commission to fully consider the TDA proposal in the appropriate context, whether in this docket or in a separate proceeding. California Commission states that a movement of OATT policy in the direction implied by the TDA proposal is necessary to improve efficiency of generation and transmission investment. BP Energy believes that a redispatch mechanism is necessary to minimize aggregate consumer costs and make redispatch equally available to all participants. PPM supports the TDA proposal noting that it would provide sufficient cost certainty for both the transmission provider and the customer and make more efficient use of the existing grid without impacting reliability. Although it opposed the proposal initially, MISO states that it now cautiously supports the TDA redispatch proposal, provided that RTOs do not bear an inappropriate share of costs to modify information technology systems.

[672] Transparent Dispatch Advocates Reply at 5.

[673] *E.g.*, EPSA and AWEA Supplemental, Constellation Supplemental, California Commission Supplemental, PPL Supplemental, BP Energy Supplemental, PPM, and San Diego G&E.

1106. Many commenters oppose the TDA proposal stating that the record in this proceeding does not warrant implementing such a complex and uncertain proposal which imposes significant risks, costs and burdens on transmission providers and their native load customers.[674] Public Power Council, Southern, and NRECA do not believe that the Commission should adopt the TDA proposal without an analysis of costs and benefits and note that no party has provided any such analysis. OG&E and Public Power Council state that the costs of congestion likely vary greatly by region and argue that Transparent Dispatch Advocates have provided no evidence that their industry-wide solution solves potential regional redispatch problems.

1107. Several state commissions oppose adoption of the TDA proposal or urge the Commission to impose significant conditions on the proposal to protect retail customers.[675] SEARUC, Alabama Commission, Florida Commission, Georgia Commission, North Carolina Commission and South Carolina Regulatory Staff express concern that the TDA proposal would make competitively sensitive information available to the public on an inconsistent basis, compel the provision of additional services that risk increasing retail costs, harm reliable service to retail ratepayers that state commissions are obligated by state laws to protect, impose administrative difficulties and excessive implementation costs, and compel states or regions to change current practices or market structures in contradiction of EPAct 2005. SEARUC asks the Commission to make clear that implementation of a proposal targeted at enhancing transparency will not result in a federally imposed change in economic dispatch practices or lessen the amount of firm capacity available for service to native load customers. SEARUC also expresses concern regarding the imposition of incremental costs upon retail ratepayers without prior state approval or the implementation of any type of process or organization that has not been approved by state regulators as cost effective for retail customers. SEARUC opposes the mandatory use of LMP or LMP-like pricing, congestion management approach or organized wholesale market structure without prior state endorsement; and the mandatory posting of competitively sensitive, generation plant-specific costs or price information.

1108. Georgia Commission states that radical restructuring is not necessary to achieve the goals stated by the Commission in the NOPR. Alabama Commission, Georgia Commission and South Carolina Regulatory Staff state that analyses associated with potential implementation of new market structures in the Southeast have demonstrated that the implementation costs associated with such structures vastly outweigh the benefits. North Carolina Commission argues that the TDA proposal fails to comply with the Commission's directive in the NOI. In its view, the Commission intended to focus in this proceeding on specific problems that continue to exist and targeted remedies.

1109. North Carolina Commission states that the Transparent Dispatch Advocates' reply comments incorrectly equate the use of redispatch for economic purposes pursuant to 13.5 of the *pro forma* OATT with its use for reliability purposes. North Carolina Commission maintains that these services are not comparable, and thus the use of redispatch for reliability purposes does not justify requiring a transmission provider to provide it for economic purposes. North Carolina Commission asserts that implementation of the TDA proposal would result in substantial benefits accruing to PJM without commensurate benefits to non-RTO areas. North Carolina Commission, Southwest Utilities and Southern argue that the costs of implementing the proposal are not justified by any potential efficiency benefits and thus there is a compelling reason to reject the TDA proposal.

1110. Several parties argue that the TDA proposal represents a move toward Standard Market Design (SMD).[676] Alabama Commission, Georgia Commission and North Carolina Commission submit that the TDA proposal shares characteristics with the centralized dispatch and LMP proposals advanced in the SMD proceeding and thus conflict with state commission jurisdiction in much the same manner as the SMD proposal. Georgia Commission and others assert that the only difference between the SMD proposal and TDA proposal is that the TDA proposal would require transmission providers, but not third party merchants, to make their costs transparent.[677] NRECA believes that a real-time pricing scheme based on some value other than actual costs constitutes the creation of a new product and an organized, bid-based market in regions that have not adopted such market structures. NRECA contends that it would be politically unacceptable to reform the OATT in a manner that necessitates the formation of regional bid-based markets in non-RTO areas.

1111. In contrast, California Commission supports the TDA proposal to the effect that transmission providers should be required to post redispatch cost information and to provide real-time redispatch. In supplemental comments, California Commission asserts that this effort is needed to prevent undue discrimination, for improved efficiency of generation and transmission investment and to improve the efficiency, transparency and openness of redispatch, and transmission access generally.

1112. Some commenters argue that the TDA proposal is necessary to remedy undue discrimination.[678] Others disagree.[679] Transparent Dispatch Advocates contend that making real-time economic dispatch available to ''non-network transmission customers'' is necessary to remedy undue discrimination against those customers as compared with network customers. In their supplemental comments, EPSA and AWEA state that the TDA proposal is necessary to remedy the same undue discrimination targeted by the NOPR proposal pertaining to planning redispatch service. PPL suggests that the TDA proposal may permit transmission customers to benefit from redispatch, which transmission owners in non-RTO

[674] *E.g.*, LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, Southern Supplemental, Southwest Utilities Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, Alabama Commission Supplemental, Florida Commission Supplemental, Georgia Commission Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff, and SEARUC Supplemental.

[675] *E.g.*, Alabama Commission Supplemental, Florida Commission Supplemental, Georgia Commission Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff, and SEARUC Supplemental.

[676] Commenters reference a proposal in a proceeding terminated by the Commission. *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design,* 67 FR 55454 (Aug. 29, 2002), FERC Stats. & Regs. ¶ 32,563 (2003), *terminated by,* 112 FERC ¶ 61, 073 (2005).

[677] *E.g.*, Community Power Alliance Supplemental, and Entergy Supplemental.

[678] EPSA and AWEA Supplemental, BP Energy Supplemental, California Commission Supplemental.

[679] *E.g.,* LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, South Carolina Regulatory Staff Supplemental, and North Carolina Commission Supplemental.

areas now employ to benefit themselves or their native load customers.

1113. A number of commenters assert that neither the record nor Transparent Dispatch Advocates present evidence of discriminatory treatment of transmission customers with regard to transparent redispatch.[680] South Carolina E&G asserts that implementation of the TDA proposal should not be unjustifiably forced onto individual transmission providers given that there is no demonstration that there is a problem. MidAmerican and Progress Energy and others argue that unsupported assertions of undue discrimination are insufficient to support the TDA proposal. These commenters argue that pursuant to the recent *National Fuel* decision, the courts would likely require the Commission to overcome substantial hurdles in order to adopt the TDA proposal based on theoretical assertions of undue discrimination.[681] These commenters contend that the *National Fuel* case would likely require the Commission to demonstrate how potential undue discrimination justifies a costly redispatch proposal, why section 206 rights are insufficient to ensure redispatch is comparably provided, and why the comparability findings of Order No. 888 are no longer sufficient.

1114. In response to assertions that utilities routinely redispatch to meet electric load, LPPC argues that there is nothing discriminatory about a vertically integrated utility's use of its own nonjurisdictional generation to support bundled sales service. LPPC states that the use of generation first to serve native load has been the fundamental operating principal for jurisdictional and nonjurisdictional utilities for decades, and certainly under Order No. 888. LPPC concludes that this is not a problem calling for Commission attention. In response to assertions that TLRs are discriminatory, Duke notes that neither the Transparent Dispatch Advocates nor any other commenter has provided an analysis of the scope, location and magnitude of the TLR problem.

1115. Many commenters contend that the TDA proposal is ambiguous, insufficiently developed or marked by inconsistencies.[682] Pacific Coast Parties argue that the TDA proposal is too sweeping and contains too many uncertainties to allow for meaningful comment. Southwest Utilities believe that it would be premature for the Commission to adopt the TDA proposal without further development, comment, discussion and input from affected electric industry stakeholders. PPL and Xcel believes that the Commission needs to better define the proposed new service and allow comment on the service before detailed tariff language is developed to implement this proposed new service. Public Power Council contends that, although the proposal appears to seek only the posting of information, in reality, Transparent Dispatch Advocates ask that the Commission require reciprocal redispatch coordination. Public Power Council also argues that the TDA proposal is silent or ambiguous concerning critical issues associated with implementation; the proposal fails to explain the ''cost'' at which transmission providers would offer redispatch or the price, terms, and conditions of such a transaction.

1116. Several parties refer to seeming discrepancies between Transparent Dispatch Advocates' explanations of the proposal and question whether the TDA proposal entails cost-based or market-based bidding.[683] APPA notes that Transparent Dispatch Advocates state in reply comments that effective redispatch service must reflect actual costs. APPA adds that the TDA Summary, in contrast, provides that any generator with market-based rate authority in the transmission provider's control area could charge a market-based price for generation offered for redispatch service. LPPC, TDU Systems, TAPS, APPA and NRECA express concern about allowing redispatch providers to bid under market-based rate authority. These commenters argue that reliance on existing market-based rate authority to support redispatch offers no protection against the exercise of market power, given the high concentration of transmission provider-owned generation within its control area. If the Commission adopts the TDA proposal, APPA asserts that the Commission should limit all sellers of generation used for redispatch service to cost-based bids and require all parties to provide cost information.

1117. In supplemental comments, EEI and Public Power Council assert that the Commission in seeking comment on the TDA proposal has not proposed a rule with sufficient clarity to allow meaningful comment and, therefore, it would be inappropriate to adopt the TDA proposal based on this proceeding's record. Pacific Coast Parties add that the Commission cannot adopt the TDA proposal based on the sparse record in this proceeding. MidAmerican and Progress Energy contend that the Commission's notice here does not satisfy Administrative Procedure Act requirements for public notice and comments on the TDA proposal. In their view, the Commission must initiate a separate rulemaking proceeding to evaluate the TDA proposal.

1118. Progress Energy and MidAmerican assert that, under the current *pro forma* OATT, redispatch is based on a ''careful'' evaluation of the reliability and cost impacts of using redispatch on a long-term basis and thus the transmission provider is able to serve transmission customers and wholesale load-serving obligations at least cost. In their view, the transmission provider's retail and wholesale customers would absorb the costs to serve transmission customers that obtain the forced real-time redispatch under the TDA proposal.

1119. Community Power Alliance, North Carolina Commission, Progress Energy and MidAmerican contend that native load customers would be harmed by a requirement that transmission providers sell their excess generation to redispatch customers. They state that such a requirement would prevent or reduce the sale of generation in competitive markets and that these market sales would otherwise reduce costs to native load customers. Moreover, where the transmission provider is required to redispatch its own generation, Progress Energy and MidAmerican argue that Transparent Dispatch Advocates' proposed redispatch would either use more expensive units or cause the transmission providers to lose the opportunity to make higher valued sales, which also increases costs for native load customers.

1120. In supplemental comments, E.ON, Progress Energy and MidAmerican assert that some generators face limits with regard to the

[680] *E.g.,* LPPC Supplemental, Community Power Alliance Supplemental, Public Power Council Supplemental, Pacific Coast Parties Supplemental, EEI Supplemental, Duke Supplemental, MidAmerican and Progress Energy Supplemental, South Carolina E&G Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, North Carolina Commission Staff Supplemental, and North Carolina Commission Supplemental.

[681] *E.g.,* Entergy Supplemental, LPPC Supplemental, Public Power Council Supplemental, and OG&E Supplemental.

[682] *E.g.,* Pacific Coast Parties Supplemental, Southwest Utilities Supplemental, Entergy Supplemental, EEI Supplemental, PPL Supplemental, Public Power Council Supplemental, Florida Commission Supplemental, SEARUC Supplemental, Progress Energy and MidAmerican Supplemental, APPA Supplemental, NRECA Supplemental, and TAPS Supplemental.

[683] *E.g.,* Progress Energy and MidAmerican Supplemental, APPA Supplemental, NRECA Supplemental, and TAPS Supplemental.

amount of time that they are allowed to operate due to air emissions caps and maintenance schedules. They contend that the TDA proposal could cause allowable run time to be ''used up'' prior to the time that the generator has fulfilled its planned native load obligation, thus requiring that the transmission provider resort to alternative, likely more expensive, power supplies for these obligations.

1121. Several parties assert that Transparent Dispatch Advocates' proposal to substitute redispatch for transmission upgrades will depress transmission investment.[684] LPPC argues that Transparent Dispatch Advocates' proposal conflicts with the Commission's policy of promoting transmission infrastructure development. NRECA states that, to the extent that redispatch is required to fulfill long-term point-to-point service on a particular transmission provider's system, such providers have failed to meet their obligations under the existing OATT to plan and expand the system for those transmission customers' long-term needs. NRECA envisions redispatch customers potentially requesting ''ever more convoluted'' dispatch rules in order to avoid transmission upgrades. NRECA prefers better enforcement of section 15.4 of the OATT in conjunction with a more open and inclusive planning process. TAPS argues that transmission providers will profit from market-based prices for redispatch and will be discouraged from transmission expansion. TAPS contends that PJM has conceded that LMP signals have proven insufficient to create a robust grid. In TAPS view, this counters Transparent Dispatch Advocates' claims that their proposal will reveal the value of transmission upgrades and encourage investment.

1122. Several commenters submit that the TDA proposal raises Standards of Conduct issues.[685] They argue that requiring the TDA proposal would complicate if not undermine the functional separation and information sharing policies of the Standards of Conduct because the transmission function would be performing merchant, or at least merchant-related, functions. According to Community Power Alliance, the requirement that transmission providers allow merchant generators to offer to sell generation to alleviate constraints in order that other customers' transactions could flow would violate Standards of Conduct.

1123. TAPS argues that accurately forecasting the price of long-term firm service may be difficult and thus the TDA proposal would not provide adequate levels of certainty to facilitate long-term service.

1124. Mark Lively asserts that the TDA proposal fails to address other types of redispatch, including loop flow, reactive power, Inadvertent Interchange and intra-hour interchange, and as such will result in suboptimal operation of the network.

1125. OG&E questions whether the TDA proposal would apply to RTOs but if so, OG&E argues that the proposal should be rejected. OG&E contends that the Commission explained in Order No. 2000 that congestion management is a regional function and that the TDA proposal should not apply to a transmission provider located within an RTO.

1126. In supplemental comments, Transparent Dispatch Advocates contend that the transparent dispatch proposal would not involve the establishment of organized markets of any sort; rather, it simply would require the posting of redispatch costs. Transparent Dispatch Advocates state that the proposal only requires the consideration by the transmission provider of additional price data from non-network resources and minimal adjustments in transmission provider's reporting systems.

1127. Several parties disagree with Transparent Dispatch Advocates and argue that the proposal would require the establishment and operation of markets by transmission providers.[686] APPA and TDU Systems assert that under the TDA proposal transmission providers would select bids, from among a variety of affiliated and unaffiliated resources, that most effectively relieve constraints. Community Power Alliance, Georgia Commission, Southern and Entergy assert that the TDA proposal would result in the establishment of formal LMP markets in non-RTO/ISO areas, or at least start down the ''slippery slope'' to LMP markets. Community Power Alliance and Entergy contend that adoption of the TDA proposal is in conflict with the purpose of the rulemaking as stated in the NOPR and Congress' focus on protecting native load and ensuring reliability in EPAct 2005.

1128. APPA argues that the implementation of the TDA proposal would require the following: designation and posting by the transmission provider of chosen flowgates; posting by the transmission provider of the desired characteristics of generation or demand-side responses that could alleviate such constraints; posting by the transmission provider of historical redispatch costs; resolution of whether public utility transmission providers can be required to provide generation resources for redispatch; resolution of whether transmission providers would be discriminated against if they were not permitted to charge market-based rates; administration by the transmission provider of short-term (daily or hourly) market for redispatch, notwithstanding a conflict of interest between the transmission provider's market-making and market-participant roles and possibly third-party monitoring of market administration.

1129. APPA, Xcel, North Carolina Commission, and NRECA raise concerns over the costs of establishing and administering redispatch markets and systems, including the costs of hardware, software, communication systems, billing and reporting systems. North Carolina Commission submits that the costs of implementing the TDA proposal would be substantial because there are no current practices or rules on which to model structures for the TDA proposal. Other commenters similarly assert that the TDA proposal would impose significant administrative burdens and expenses on transmission providers, especially if an independent entity were required for implementation, and that most of these costs would be shifted to native load customers.[687] Xcel argues that redispatch cannot be cost-effectively managed unless done within the context of a regional Day 2 energy market.

1130. NRECA asserts that transmission providers would need an enormous amount of data, including resource status, marginal generation costs, start up costs, ramp rates, and environmental costs of operation, to redispatch resources. NRECA asserts that the allocation of redispatch costs for multiple customers taking redispatch may be difficult.

[684] *E.g.*, LPPC Supplemental, TAPS Supplemental, NRECA Supplemental, Southern Supplemental, South Carolina E&G Supplemental, and E.ON Supplemental.

[685] *E.g.*, Nevada Companies Supplemental, Community Power Alliance Supplemental, Southwest Utilities Supplemental, and Southern Supplemental.

[686] *E.g.*, APPA Supplemental, LPPC Supplemental, TDU Systems Supplemental, NRECA Supplemental, Progress Energy and MidAmerican Supplemental, Southern Supplemental, Duke Supplemental, OG&E Supplemental, Georgia Commission Supplemental, and North Carolina Commission Supplemental.

[687] *E.g.*, Community Power Alliance Supplemental, Southwest Utilities Supplemental, Florida Commission Supplemental, Ameren Supplemental, and Entergy Supplemental.

1131. Xcel, APPA, and TDU Systems assert that the TDA proposal would not address concerns about subjective redispatch decisions by transmission providers. TDU Systems argue that the proposal would allow for the functional equivalent of an RTO market, without a market administrator that satisfies the independence criteria of Order No. 2000 or Order No. 888. APPA asserts that posting of information concerning the nature of congestion at designated flowgates would be followed by differences of opinion as to how the dispatch entity is exercising its judgment in calculating the costs and in redispatching resources.

1132. Southwest Utilities and Southern assert that the proposal raises significant questions regarding commercial, operational, economic, and compliance issues that remain unanswered. For example, Southwest Utilities argues that it would appear that under the TDA proposal a transmission provider accepting a third party bid would be required to assume the commercial obligation, including credit risk associated with the bid and the posting of collateral, and would execute the contract with the third party bidder under currently unspecified terms and conditions. Southwest Utilities and Southern further argue that the proposal fails to resolve how operational and economic liability to the redispatch customer would be impacted in the event of non-performance by a third party supplier. Southwest Utilities also asserts that it is unclear whether the TDA proposal could function within the rated path/contract path model of much of the Western Interconnection.

1133. Many parties argue that implementation of the TDA proposal would raise jurisdictional issues.[688] Community Power Alliance, South Carolina E&G, Progress Energy, MidAmerican and Southern assert that the TDA proposal conflicts with state and federal laws in that it forces transmission providers to use generation (that was built, dedicated and dispatched to serve retail and wholesale customers at least cost) to serve other wholesale suppliers and customers. Community Power Alliance argues that states, not the Commission, have authority to regulate how utilities dispatch generation and procure resources. Further, Community Power Alliance asserts that requiring utilities to establish platforms for third-party generators' offers would convert the transmission function into a generation procurement function, violating the scope of the Commission's jurisdiction. Southern, LPPC and North Carolina Commission add that the TDA proposal would be in violation of section 201 of the FPA that expressly limits the Commission's jurisdiction to matters which are not subject to regulation by the States. Southern further asserts that this is made clearer by the exclusion in section 201 of ''facilities used for the generation of electric energy'' from the Commission's jurisdiction. Southern contends that mandated cost-based sales would also constitute an unlawful taking of private property under the Fifth Amendment of the Constitution.

1134. LPPC states that Transparent Dispatch Advocates seek to reason around section 201 of the FPA in arguing that redispatch ''does not involve the sale of electricity for re-sale or consumption; it involves the provision of a service to support transmission service.'' [689] LPPC counters that, in redispatch, generation is used *instead* of transmission service rather than *in support* of transmission service. North Carolina Commission, LPPC and APPA argue that the courts have previously rejected Commission attempts to extend regulation to matters specifically excluded, statutorily, from regulation on the grounds that they are the functional equivalent of a jurisdictional service.[690] LPPC also asserts that section 217 of the FPA specifies that utilities have a right to use their transmission facilities on a priority basis in order to meet their core service obligations.

1135. North Carolina Commission asserts that in Order No. 888 the Commission interpreted its authority under sections 205 and 206 of the FPA to include the effect the Rule may have over generation facilities because preventing undue discrimination is one of the matters specifically provided for in Part II. North Carolina Commission argues that *California Independent System Operator* v. *FERC,*[691] however, establishes limits on how broadly sections 205 and 206 can be interpreted. North Carolina Commission contends that sections 205 and 206 historically have been interpreted to apply to the rates for wholesale sales and purchases, rather than to the underlying generating facilities. As a result, North Carolina Commission argues that the adoption of the TDA proposal could not be justified under these provisions of the FPA.

Commission Determination

1136. The Commission agrees with the Transparent Dispatch Advocates proponents that greater transparency of reliability redispatch information can provide benefits to consumers, as well as increase efficient use of the existing transmission grid. We are therefore adopting certain reforms, as explained in the section below, that will increase the availability and transparency of redispatch costs. However, we are adopting these reforms in the context of the existing obligation to provide network and point-to-point transmission service under the *pro forma* OATT. We will not adopt the portion of TDA proposal that would require the creation of new services or any broader market reforms.

1137. The TDA proposal has generated controversy for several reasons, including the lack of clarity in the proposal, certain inconsistencies that appear in Transparent Dispatch Advocates' various submissions, and concerns that Transparent Dispatch Advocates' true intent is to restructure bilateral markets. We believe that many of the concerns regarding the TDA proposal are overstated, but we do agree that it lacks clarity and consistency in many important respects. For example, it is not clear whether the proposed service would be available to all customers, any point-to-point customer including those taking non-firm service, or solely to long-term firm point-to-point customers.[692] Additionally, while Transparent Dispatch Advocates contend that ''the one step'' required of the Commission is to implement a redispatch cost posting requirement,[693] the TDA proposal also would require the Commission to expand the current redispatch obligations under the *pro forma* OATT and adopt complex settlement mechanisms to account for third party redispatch. The different TDA proposals also vary as compared with each other. For instance, the TDA Summary states that transmission providers would not be obligated to provide their resources for real-time redispatch, but the Transparent

[688] *E.g.*, APPA Supplemental, LPPC Supplemental, Community Power Alliance Supplemental, South Carolina E&G Supplemental, Progress Energy and MidAmerican Supplemental, and Southern Supplemental.

[689] Transparent Dispatch Advocates Reply at 17.

[690] *Citing Northwest Pipeline Corp.* v. *FERC,* 905 F.2d 1403, 1410–11 (10th Cir. 1990); *Detroit Edison Co.* v. *FERC,* 334 F.3d 48, 54–55 (D.C. Cir. 2003).

[691] 372 F.3d 395 (D.C. Cir. 2004).

[692] *Compare* Transparent Dispatch Advocates Supplemental at 2 n.4 (stating that the proposed service would supplement the existing OATT requirement to provide redispatch to long-term firm point-to-point customers) *and* Transparent Dispatch Advocates Supplemental at 5 (discussing the proposal as a remedy for undue discrimination against firm point-to-point customers) *with* Transparent Dispatch Advocates Supplemental at 14–15 (demonstrating the redispatch pricing mechanism for a non-firm transaction).

[693] Transparent Dispatch Advocates Reply at 18.

Dispatch Advocates Supplemental Comments make clear that the transmission provider would be obligated to use its own (or affiliated) resources to provide this redispatch.

1138. We first address the contention of Transparent Dispatch Advocates that the real-time reliability redispatch obligation of transmission providers must be extended to ''non-network transmission customers'' to remedy undue discrimination. We disagree. In order to remedy undue discrimination, we have made changes to the *pro forma* OATT to implement a new conditional firm option for point-to-point service and we make changes to the existing planning redispatch obligation. However, Transparent Dispatch Advocates have failed to show that the unavailability of reliability redispatch for point-to-point transmission customers amounts to undue discrimination. Order No. 888 provided for reliability redispatch for network customers but not for firm point-to-point customers.[694] There is a good reason for this distinction. The *pro forma* OATT requires network customers to make their generation resources available to the transmission provider to provide reliability redispatch to maintain the reliability of service to both native load and network customers. There is no corresponding obligation on point-to-point customers to make their generation resources available to provide reliability redispatch. Therefore, the two services are not comparable in this respect, which is why reliability redispatch service was not required for point-to-point customers. However, if a reliability problem does arise, any curtailment of firm point-to-point transmission service must be on a nondiscriminatory and *pro rata* basis with the treatment of network service and native load customers.[695] The Commission has found that this treatment meets the comparability requirements enunciated in Order No. 888.[696]

1139. Next, we also decline to adopt a requirement for transmission providers to incorporate offers to redispatch from third parties into their reliability redispatch or planning redispatch. Mandatory inclusion of third party offers is not necessary to remedy undue discrimination. The *pro forma* OATT obligates transmission providers to use their resources to provide, where available consistent with reliability, redispatch service because they do so when serving their native load customers. Third party generators do not have this obligation, nor do the Transparent Dispatch Advocates propose to create such an obligation. Rather, under the TDA proposal, transmission providers would remain obligated to provide redispatch service, but third party generators would have only the option of doing so. Transparent Dispatch Advocates are therefore not proposing comparable treatment and we decline to adopt the proposal. This notwithstanding, we believe that redispatch offers by third party generators can increase system reliability and reduce costs to customers by increasing the planning redispatch options available to transmission providers. We therefore are adopting, as explained above, a requirement that transmission providers modify their OASIS to allow for the posting of third party offers to supply planning redispatch. This OASIS posting requirement does not obligate transmission providers to incorporate bids from third parties into their redispatch; rather, posting of third party offers to provide redispatch may be used by transmission customers to secure planning redispatch provided the appropriate agreements are reached between the customer, third party redispatch provider, transmission provider and reliability coordinator.

1140. We disagree with Transparent Dispatch Advocates and their supporters that their proposal for real-time redispatch and third party generation participation would allow for additional long-term rights through planning redispatch. If third party participation in the offer of redispatch is voluntary, transmission providers would not be able to depend upon third party resources in evaluating the availability of resources during the term of the planning redispatch service. Transmission providers therefore would only be able to evaluate the availability of their own resource as they do today. Thus, Transparent Dispatch Advocates have failed to show how its proposal would supplement provision of long-term rights.

1141. Because we find that the TDA proposal for real-time redispatch and third party participation is unnecessary to remedy undue discrimination or comparability issues, we need not address the issue of the scope of the Commission's jurisdiction as it relates to the TDA proposal.

(2) Redispatch Rate Transparency

Comments

1142. PJM argues that if the Commission does not provide for independently administered real-time spot markets, it should require transmission providers to ''make public their dispatch sequence and the real-time marginal costs of electricity.''[697] In reply comments, Transparent Dispatch Advocates request that the Commission require publication of ''dynamic real-time value of what [each transmission provider] would charge to provide redispatch service at specified congestion locations within the transmission provider's system and at specified flowgates at the border of the transmission provider's system.''[698] In supplemental comments, Transparent Dispatch Advocates state that ''[t]he essence of the TDA proposal is to require transmission providers to make real-time information about the cost of redispatch available on their OASIS in order to allow more efficient use of the transmission system.''[699] Transparent Dispatch Advocates, EPSA and AWEA state that the posting requirement should be limited to pre-determined flowgates and that the estimated price for redispatch should be posted frequently and sufficiently in advance of the hour in which the price would be effective in order to allow the transmission customer to change its schedule and avoid redispatch charges.

1143. EPSA, AWEA and Transparent Dispatch Advocates state that since this information is available today and considered by transmission providers in serving their own native load, there are no impediments to implementing their proposed posting requirement. Transparent Dispatch Advocates argue that concerns about release of confidential data can be addressed by

[694] *See pro forma* OATT section 33.2; *see also Midwest Independent Transmission System Operator, Inc.,* 84 FERC ¶ 61,231 at 62,168 (1998) (''redispatch will be utilized to avoid the curtailment of firm point-to-point services, a requirement that is not imposed under the pro forma tariff.''); *Mid-Continent Area Power Pool,* 87 FERC ¶ 61,190 at 61,726–27 (1999) (finding no obligation to offer reliability redispatch to point-to-point customers and no obligation for point-to-point customers to participate in reliability redispatch).

[695] *See, e.g., North American Electric Reliability Council,* 88 FERC ¶ 61,046 at 61,123–24 (1999) (explaining that pro rata curtailment is consistent with comparability even if network/native load reduction is accomplished by redispatch and point-to-point customer reduction is not); *Northern States Power Co.,* 83 FERC ¶ 61,338 at 62,369 (1998) (the existence of redispatch options is not a criterion under the *pro forma* OATT for disproportionate curtailments), *reh'g, clarification and stay denied,* 84 FERC ¶ 61,128 (1998), *remanded on other grounds sub nom. Northern States Power Co.* v. *FERC,* 176 F.3d 1090 (8th Cir. 1999) (*Northern States Power*).

[696] *Northern States Power,* 83 FERC ¶ 61,338 at 62,369.

[697] PJM at 6.

[698] Transparent Dispatch Advocates Reply at 5.

[699] Transparent Dispatch Advocates Supplemental at 7.

using system costs instead of unit-specific cost data to calculate the posted redispatch price. EPSA and AWEA state that there are not confidentiality issues with the Transparent Dispatch Advocates' posting proposal because redispatch costs are not the costs that the transmission provider is incurring to sell energy into the market: they contend that redispatch costs are the net cost incurred by the transmission provider, *e.g.*, the difference between the costs of ramping up and ramping down resources. EPSA and AWEA also state that there would be no competitive concerns over the posting of this information from third party suppliers because the *suppliers names need not be* used.

1144. Some commenters do not believe that making certain information publicly available will result in confidential information disclosure.[700] PPL states that while confidentiality concerns must be considered, the nature and type of information that is publicly provided may be structured so as to alleviate or minimize such concerns. PPL argues that rather than posting specific generator cost information the all-in price for redispatch may be posted instead. BP Energy argues that posting redispatch prices at specified locations reveals the economic value of adding transmission/generation at those locations, but does not reveal the production cost associated with specific generation resources. BP Energy states that hourly redispatch costs should be posted for all ''significant congested interfaces'' within a transmission provider's control area and for all interfaces at control area boundaries. PGP asserts that transmission providers with OATTs should post any available information on hourly redispatch costs.[701] PGP and PPL argue, however, that there should be an appropriate lag in the disclosure of actual redispatch costs in order to address confidentiality concerns. Williams states that increased transparency and proper monitoring are immediate, real solutions to ''issues'' with the posting of the cost of redispatch. Williams asserts that those customers requesting redispatch should be provided the cost differential between the original dispatch and the redispatch and that post audit redispatch data and system models can be made available (after the expiration of a non-disclosure period) to provide market certainty of least cost redispatch and appropriate bid selection.

1145. PGP states that the redispatch option should be available irrespective of time frame, but must recognize the limited ability of the transmission provider to identify likely redispatch costs further out in time. Thus, PGP argues, posting redispatch costs in areas without organized markets should focus initially on real-time reliability redispatch, later expanding to longer time frames. PGP asserts that redispatch should be undertaken only when firm bids are available and the transmission customer has accepted responsibility for redispatch costs, which should be based on just and reasonable prices and must be known with a degree of certainty. PGP adds that the transmission provider should establish protocols that support firm bids, which would be published and, if accepted, result in binding obligations on the part of the bidders. PGP argues that it is reasonable for transmission providers to post real-time bids on constrained paths that are otherwise subject to curtailments to ensure compliance with reliability criteria. PGP contends that postings should take place on the transmission providers' OASIS and that all information should be retained by the transmission provider. PGP submits that redispatch bids should be explicitly added to the Commission's Electric Quarterly Reports filing requirements if not already required.

1146. Constellation argues that the Commission should require each transmission provider to post two values to the market on its OASIS site, in order to enhance transparency: historical costs of redispatch at certain specified flowgates (perhaps those most congested historically) and real-time redispatch costs at the same flowgates. Constellation submits that each transmission provider engages in redispatch and thus can readily ascertain the cost of redispatch at various locations. Constellation argues that posting such costs will enable transmission customers to more accurately assess the potential costs of redispatch prior to deciding to incur redispatch costs. Constellation adds that the customer receiving redispatch should be obligated to pay the actual costs of redispatch, regardless of the costs reflected in the postings, which, Constellation contends, should reflect the transmission provider's most accurate and up-to-date information.

1147. Williams believes that Transparent Dispatch Advocates' redispatch proposal offers a partial remedy to transmission congestion caused by insufficient infrastructure and undue discrimination. Williams proposes that affiliate and third-party generators submit either a pre-established rate structure or formulary pricing methodology prior to the provision of redispatch service. Williams states the primary implementation impediment to greater transparency of redispatch cost information is the accuracy and availability of redispatch costs.

1148. BP Energy submits that posting the costs of redispatch is not the same as posting operational cost curves of specific generating units. BP Energy adds that, given the availability of redispatch costs, there is no reason to post the differential in unit-specific costs as a supplement to marginal prices posted at significant locations throughout the control area. PGP states that there is no need to establish markets to provide real-time redispatch. Rather, PGP asserts that limited protocols can be established for specific locations or types of congestion that may be directly relieved via redispatch. PGP believes that the Commission should avoid establishing detailed rules governing redispatch protocols, but rather should permit regional practices to be developed that result in ''just and reasonable'' charges for redispatch service.

1149. In its reply comments, Southern states that requiring vertically integrated utilities to post their real-time marginal costs of electricity would be discriminatory and violate the Trade Secrets Act.[702] Southern states that RTOs do not make public the marginal costs of the utilities participating in their markets, thus requiring other transmission providers to do so would be discriminatory. Southern states that marginal costs information is commercial or financial information protected by federal statute that if released would put it at a competitive disadvantage and harm its customers by allowing competing generators to price their power just below the published marginal costs.

1150. Several parties assert that the TDA proposal would require the posting of vertically integrated utilities' generation costs and thus would provide competitors and buyers with commercially-sensitive information.[703]

[700] *E.g.*, EPSA and AWEA Supplemental, BP Energy Supplemental, and California Commission Supplemental.

[701] PGP asserts that the transmission provider should be required to post redispatch information by event and by entity to address concerns about anticompetitive behavior.

[702] 18 U.S.C. 1905.

[703] *E.g.*, Entergy Supplemental, Community Power Alliance Supplemental, Progress Energy and MidAmerican Supplemental, Southern Supplemental, Southwest Utilities Supplemental, Nevada Companies Supplemental, OG&E Supplemental, Florida Commission Supplemental, PPL Supplemental, Ameren Supplemental, North Carolina Commission Supplemental, and SEARUC Supplemental.

Many of these parties assert that posting a utility's incremental costs publicizes the price at which the utility elects to operate resources rather than purchase from a third-party.[704] EEI and South Carolina E&G assert that making this information public may adversely affect competition and markets. Duke argues that having the transmission provider post daily and hourly generator costs assigns it responsibilities that are beyond the typical transmission function. Duke urges the Commission to consider voluntary alternatives to resource-specific cost information that would divulge competitively-sensitive data. SEARUC argues that any incremental transparency improvements not be implemented in such a manner as to make competitively sensitive information available to the public on an inconsistent basis. Nevada Companies assert that the requirement to make such information publicly available to the transmission provider would have to be imposed upon all generators, including independent power producers, so that such information would lose the value it derives from not being publicly known.

1151. Entergy argues that the Commission is statutorily prohibited from requiring the disclosure of information that undermines fair competition under the electric market transparency provisions in sections 220(b)(1) and (2) of the FPA.[705] South Carolina E&G submits that the TDA proposal is inconsistent with this provision of the FPA. Southern further contends that mandating that transmission providers post and offer their generation on an at-cost basis, while allowing third party generators to submit bid prices would also be discriminatory. TAPS asserts that the proposed real-time disclosure of bid and cost information runs contrary to the Commission's policy of a 6-month delay for release of bid information.

1152. NRECA asserts that the Transparent Dispatch Advocates fail to explain why transmission providers coordinating with third parties or neighboring transmission providers will not run afoul of anti-trust and collusion concerns that they are colluding in price setting; and how to verify providers are selecting the lowest bid unless they are required to post all third party generator bids as well as their own or their affiliates' cost of providing the service.

1153. Ameren asserts that the existing OATT contains requirements for information to be posted by transmission providers, and does not believe that additional posting ought to be required. Ameren provides several recommendations were the Commission to adopt some or the entire TDA proposal. First, Ameren asserts that there are many different ways to estimate this cost and, in order to avoid the creation of competing methods for estimating redispatch costs, the Commission must consider and provide guidance on several questions.[706] Second, so that transmission providers are not disadvantaged by this new obligation, Ameren urges the Commission to develop detailed requirements, including uniform timelines for posting, guidelines for estimating cost, and inclusion of all dispatchable generation in the relevant footprint. Ameren further argues that posting only the difference in costs would not address the potential for anticompetitive impacts. Finally, Ameren contends that the Commission may wish to consider implementing the changes only on an interim basis, then to observe whether there is any market benefit or any competitive harm as a result of the new requirements.

1154. Duke believes that the posting of hourly redispatch costs would create near-constant off-OASIS communications between the transmission provider and merchant function employees, which, Duke asserts, would raise Standards of Conduct concerns.

1155. NRECA argues that allocated costs may vary significantly regardless of methodology, which devalues the posting of costs. North Carolina Commission argues that publishing indicative redispatch costs in real time would require a determination as to how such costs are determined and whether each component of such costs are appropriately charged to customers.

Commission Determination

1156. After careful consideration of the comments of the parties, we adopt a posting obligation that balances several competing considerations. First, we agree with Transparent Dispatch Advocates and supporting parties that the increased availability of information regarding redispatch costs can benefit consumers and increase the efficient use of the grid. Second, we are cognizant, however, that increased posting and reporting can impose cost burdens on transmission providers or otherwise harm market participants. For example, the reporting obligations can reveal confidential information that could harm market participants or increase the cost of serving native load customers. We also recognize that the posting or reporting obligation should be reasonably tailored to provide useful information to consumers without, at the same time, imposing unnecessary burdens on transmission providers, either in the frequency of the posting obligation or the scope of information provided.

1157. In balancing these considerations, we will, as explained further below, adopt a requirement that transmission providers post certain redispatch cost information associated with the existing redispatch services that must be provided under the *pro forma* OATT. We find that providing customers with additional transparency and greater information regarding the cost of congestion, will facilitate their consideration of planning redispatch options which in turn will provide for more efficient use of the grid. We stress, however, that this posting requirement relates only to the existing redispatch services required under the *pro forma* OATT; it does not expand those service obligations. The primary purpose of the posting requirement is to ensure that all customers have access to this information, not only the customer receiving the redispatch service.

1158. Moreover, the costs of the dynamic posting requirement proposed by Transparent Dispatch Advocates outweigh the benefits of such a requirement. Transparent Dispatch Advocates propose that the posting requirement be limited to specified congestion locations within and at the border of each transmission provider's system. Transparent Dispatch Advocates have not proposed *ex ante* criteria to determine which flowgates would require posting. In fact, some members of the Transparent Dispatch Advocates coalition would have the posting requirement apply to all transmission facilities, whether or not they were

[704] *E.g.*, Entergy Supplemental, Community Power Alliance Supplemental, Southern Supplemental, Duke Supplemental and South Carolina E&G Supplemental.

[705] Entergy refers to the following language:

(1) The Commission shall exempt from disclosure information the Commission determines would, if disclosed, be detrimental to the operation of an effective market * * *; and (2) [i]n determining the information to be made available under this section and the time to make the information available, the Commission shall seek to ensure that consumers and competitive markets are protected from adverse effects of potential collusion and other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information.

[706] Ameren raises several questions to this effect: Does the transmission provider estimate cost effect across all market LMPs or just the congested points? Should the analysis take into account credits and adjustments to which some participants may be entitled? For what period should the transmission provider provide this estimate? For those transmission providers within a centralized market, how should they treat market costs such as losses or RSG (Revenue Sufficiency Guarantee in MISO) in calculating the redispatch cost?

congested and whether or not customers were seeking service over those facilities. Such an open-ended obligation to post costs for all facilities on a transmission provider's system would unnecessarily impose uncertainties and unbounded administrative costs on transmission providers. Additionally, depending on the frequency of publication and the method used to calculate the estimates, the publication of these estimates could reveal sensitive confidential information about transmission providers' generation costs that would likely harm existing markets and native loads. There is no simple formula for estimating the costs that would fully mask this confidential information and at the same time provide practical information about the costs of redispatch.

1159. While we agree that transparency can benefit customers, Transparent Dispatch Advocates have not demonstrated the benefits of its posting requirement to customers seeking reliability or planning redispatch. Transparent Dispatch Advocates would have transmission providers frequently post an estimate of the cost of the next increment of redispatch. Customers seeking redispatch would not know the actual costs customers paid for redispatch. Nor would they be able to apply the estimate of cost to their transactions since most transactions would involve more than a single increment of redispatch service and there might be multiple redispatch transactions over a single transmission facility. Thus the estimate would only be of value to the marginal customer taking a small amount of redispatch service. Transmission providers would expend time and money determining the correct formula to use to estimate costs, collecting data for the inputs to the calculation and frequently posting estimates throughout each day that could have little or no correlation to the actual costs a transmission customer would pay for the redispatch service.

1160. Third party participation in redispatch is one of the benefits Transparent Dispatch Advocates point to in support of its proposed posting requirement. Transparent Dispatch Advocates would have transmission providers act as the conduit for service from third party redispatch providers, collecting from customers and paying third party providers. As described above, we are allowing third party participation in planning redispatch without requiring transmission providers to act as bill collectors for third party redispatch providers or requiring coordination agreements among each transmission provider and all potential third party providers. This OASIS modification, described above, will provide third parties seeking to provide redispatch with the opportunity to frequently update the price of their offers as suggested by Transparent Dispatch Advocates.

1161. We do believe, however, that information regarding actual redispatch costs should be made more widely available. Currently, when a transmission provider provides reliability or planning redispatch, the associated cost information is provided only to the customer receiving the service through its invoices. This ignores the fact that information regarding the cost of redispatch can benefit all customers and increase the efficient use of the grid. We therefore find that it is no longer just, reasonable and not unduly discriminatory to limit the provision of this information only to the individual customers receiving the service.

1162. Accordingly, to provide greater availability of redispatch information, the Commission adopts certain additional posting requirements for transmission providers. Specifically, we direct each transmission provider to post on OASIS its monthly average cost of redispatch for each internal congested transmission facility or interface over which it provides redispatch service using planning redispatch or reliability redispatch under the *pro forma* OATT.[707] Additionally, to demonstrate the range of redispatch costs each month, the Commission directs transmission providers to post a high and low redispatch cost for the month for each of these same transmission constraints. The transmission provider shall calculate the monthly average cost in $/MWh for each congested transmission facility by dividing monthly total redispatch costs (at the facility) by the total MWhs that would otherwise be curtailed (at the facility) in the month absent the redispatch.[708] Transmission providers shall post internal constraint or interface data for the month if any planning redispatch or reliability redispatch is provided during the month, regardless of whether the transmission customer is required to reimburse the transmission provider for those exact costs. Thus, if the transmission customer pays for redispatch pursuant to a negotiated fixed rate, the transmission provider is required to post and calculate the monthly average redispatch costs and the high and low costs in the month even though the transmission provider will bill the customer the fixed rate. The same posting requirement applies if the customer is paying a monthly ''higher of'' rate.[709] The transmission provider shall post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for redispatch-related services. We direct transmission providers to work in conjunction with NAESB to develop this new OASIS functionality and any necessary business practice standards.

1163. There are several benefits to this posting requirement. First and foremost, it will give customers fairly current information regarding the cost of redispatch of the congested transmission facilities over which redispatch is provided, presumably some of the most congested facilities on transmission providers' systems. Second, it will limit posting only to those congested transmission facilities over which redispatch has actually been sought and granted and for which redispatch charges have been billed to customers. This addresses commenters' concerns about the posting of information that is valuable only hypothetically. Third, because we require the posting of average redispatch costs, not real-time redispatch costs or real-time system lambda or system incremental costs, it will not be harmful to native load or reveal otherwise competitively sensitive information.

1164. Finally, in addition to the above posting requirement, we note that, as part of the transmission planning provisions adopted in this Final Rule, we are providing customers with a right to request a study of a defined number of congested transmission facilities on an annual basis. This will provide customers an additional opportunity to evaluate redispatch costs, including costs for those congested transmission facilities for which redispatch service has not been granted.

[707] The relevant reliability redispatch costs for posting purposes are those costs the transmission provider invoices network customers based on a load ratio share pursuant to section 33.3 of the *pro forma* OATT. The transmission provider need not perform new calculations of out-of-merit dispatch costs; rather the reliability redispatch invoices should form the basis of information from which the transmission provider determines monthly average reliability redispatch costs.

[708] For example, if reliability redispatch is used by the transmission provider to prevent curtailment of 10 MW of transmission provider or network customer load for 5 hours during the month across flowgate A, the transmission provider would use 50 MWh as the divisor to determine the monthly average cost of redispatch for flowgate A.

[709] This is not a new calculation for the transmission provider because the transmission provider must determine the redispatch costs to know whether to charge higher of the embedded rate or the redispatch costs.

c. Other Requested Service Modifications

NOPR Proposal

1165. In the NOPR, the Commission summarized requests for various new services made in response to the NOI. The Commission's proposed solutions evaluated solely the planning redispatch and conditional firm options.

Comments

1166. Commenters make several suggestions with regard to additional services or modifications to existing services. Most popular among the suggested new services is long-term, seasonally-shaped firm point-to-point service. Several commenters support this service for circumstances in which the transmission provider determines that the requested service is available during some, but not all, months of each year of a single or multiyear request.[710] Commenters suggest that the long-term, seasonally-shaped service would provide an option for the transmission customer in lieu of costly upgrades without the operational difficulties of conditional firm service. In its reply comments, Powerex states that this product would have less of an adverse impact on existing firm rights holders. Northwest IOUs propose that the transmission customer pay the long-term point-to-point transmission service rate prorated for the portion of the year for which it receives the service. Public Power Council states that the transmission customer would be free to purchase non-firm or secondary service for the periods when firm service through the seasonally-shaped service was unavailable. Northwest IOUs argue that ''cream-skimming'' is avoided by processing only requests for long-term service and having the transmission provider determine the availability of the service.

1167. Powerex supports the implementation of a long-term non-firm point-to-point service. Tacoma believes priority non-firm or partial firm transmission services are alternatives to planning redispatch. Entegra proposes an additional service that would allow the customer, in the event of a constraint, to agree to either pay for redispatch or have its service curtailed. In contrast to these request for new services, TranServ states that simplified services and a reduction in the number of services would increase the transparency and fluidity of electricity trading.

1168. MidAmerican urges the Commission to allow for dynamic scheduling service between control areas on a case-by-case basis, by including and pricing the service in the service agreement. MidAmerican states that this service would be similar to point-to-point service, but would allow the transmission customer to dynamically monitor its loads in neighboring control areas and dispatch its own remote resource to meet the load fluctuations in load pockets served by other transmission providers. MidAmerican further states that this new service is necessary in the Western Interconnection because neither point-to-point nor network service meets the needs of loads that are not confined to a single geographic area served by a single transmission provider.

1169. Barrick states that the Commission should require transmission providers to confirm the availability of secondary service for network customers on a monthly or quarterly basis so that network customers can plan ahead for the use of secondary service. In its reply comments, Seattle supports the development of short-term redispatch service, currently under discussion for provision in the Pacific Northwest. TranServ requests that the Commission clarify whether sequential reservation of 12 consecutive months of monthly firm service is long-term service. TranServ requests that the Commission direct the development of business practices by NAESB to allow customers to designate minimum term and capacity for partial interim service, similar to the practice employed by Bonneville.

Commission Determination

1170. The Commission rejects the requests to order new services or modifications to existing services suggested by commenters. We believe that the modifications to point-to-point transmission service adopted herein best address the issues raised by these requests. The planning redispatch and conditional firm options provide a means of remedying undue discrimination, and increasing transparency and access to the grid by point-to-point customers. We note that there is considerable overlap between these options and the new services suggested by commenters. However, we find that the introduction of the requested new services may create greater complexities than those present in the planning redispatch and conditional firm options. For example, several commenters propose a long-term seasonally shaped firm point-to-point service as a superior option to the conditional firm service. However, requestors have not adequately addressed concerns about the service, including the potential for hoarding transmission and the reliability issues related to evaluating the availability of the service or granting the service over many years. A seasonally shaped service could exacerbate the lumpiness of transmission investment by preventing customers willing to pay for transmission upgrades from obtaining all twelve months of service. While we will not reduce the number of services required as suggested by TranServ, the Commission must limit the number of new services adopted and modifications to existing services to a reasonable number that transmission providers can reliably implement. For these reasons, we decline to adopt any additional proposals or modifications to firm point-to-point service beyond those directed above in this Final Rule. Of course, transmission providers remain free to voluntarily propose additional services that are consistent with or superior to the *pro forma* OATT, as modified by this Final Rule.

1171. The Commission rejects the request to adopt long-term non-firm service because there is no indication that customers would find such a service useful and it would be inconsistent with the policy in the *pro forma* OATT that values firm service over non-firm service.

1172. MidAmerican requests that the Commission allow a point-to-point service that would let a transmission customer monitor its load and dispatch its remote resources to meet load fluctuations. In Order No. 888–A, the Commission clarified that this type of dynamic scheduling was not mandated Order No. 888, but that nothing in Order No. 888 precludes a transmission provider from offering it as a separate service.[711] Thus, MidAmerican may propose such a service pursuant to an FPA section 205 filing with the Commission, and we will consider it, as we would any new service proposal, on a fact-specific, case-by-case basis.

1173. Barrick requests that the Commission require the confirmation of the availability of secondary service for network customers on a monthly or quarterly basis so that network customers can plan ahead for the use of secondary service. As we stated in the NOPR, secondary network service refers to transmission service for network customers from resources other than designated network resources and is provided on an ''as available'' basis. Since the secondary service is provided

[710] *E.g.*, MidAmerican, Public Power Council, Northwest IOUs, Xcel, Powerex Reply, PPL, and Seattle Reply.

[711] Order No. 888–A at 30,235–36.

on an as available basis, Barrick's request seeks to allow secondary network service to pre-empt firm uses of the system, such as short-term firm point-to-point service, for what is a less than firm service. Barrick has not clearly articulated why this proposal is necessary to prevent the exercise of undue discrimination or why service from designated network resources would not meet its need for firmer secondary service. Thus, we reject Barrick's request.

1174. With regard to Seattle's support for redispatch being developed in the Pacific Northwest, we believe that this type of redispatch shares many of the attributes of the Transparent Dispatch Advocates proposal rejected above. Although we acknowledge that market mechanisms that provide hour-ahead or real-time redispatch for all transmission customers can provide benefits to customers and efficient use of the transmission grid, for the reasons stated in the prior section, we will not require in this Final Rule that all transmission providers implement such market mechanisms. We note that nothing prevents the Commission from reviewing proposals for such market mechanisms on a case-by-case basis. We note that the conditional firm and planning redispatch options adopted in this Final Rule will provide some of the flexibility Entegra seeks. Customers taking service under these options will be able to choose, when executing the service agreement, between curtailment and redispatch.

1175. Also, the Commission clarifies for TransServ that twelve months of consecutive monthly firm service, where the term of any particular monthly service agreement is for less than a year, is not long-term service.[712] The Commission rejects TranServ's request that NAESB develop particular business practices regarding partial interim service as TranServ has not shown a need for such a requirement.

1176. The Commission continues to encourage transmission providers to propose other services that are consistent with or superior to the *pro forma* OATT that meet customers' needs and make more efficient use of the transmission system. We will not mandate that transmission providers provide any service other than the services set forth in the *pro forma* OATT since they may not be applicable in all circumstances. However, if transmission providers seek to provide any modifications to the required *pro forma* OATT services or new services, they may submit an FPA section 205 filing to propose such modifications and the Commission will evaluate such proposals on a case-by-case basis.

2. Hourly Firm Service

NOPR Proposal

1177. In the NOPR, the Commission proposed to add point-to-point hourly firm service to the *pro forma* OATT. The Commission stated its belief that adding this service would eliminate a barrier to the development of markets and thereby decrease opportunities for undue discrimination. The Commission further stated that the concerns expressed in Order No. 888 regarding the unduly discriminatory effects of hourly firm service have proven unfounded. Consistent with our precedent, the Commission proposed to use the ''IES Method'' to price hourly firm service and apply different pricing based on whether the service is taken during peak or off-peak hours.[713] The Commission explained that this pricing method would ensure that hourly firm customers pay a fair share of the costs of the transmission system.

1178. The Commission proposed allowing transmission customers to batch requests and schedules for hourly firm service that will be provided within the same calendar day. Schedules for firm hourly service, like all other firm schedules, would be due by 10 a.m. the day before the service is to commence. The Commission also proposed that, consistent with other durations of service, the confirmation period for hourly firm service specified in section 13.2 of the *pro forma* OATT would allow longer term requests for service to preempt shorter hourly firm requests for service until one hour before the commencement of hourly firm service.

Comments

1179. Commenters are split on whether to require hourly firm service. Varied interests express some support of the requirement, while mostly IOUs, cooperatives, and public power providers oppose the requirement. Supporters, which include several entities that currently offer hourly firm service, foresee increased use of transmission facilities and market efficiencies. Chief among the arguments cited by those objecting to the required service is the potential adverse effect on those serving native load or taking longer term service due to increased frequency of curtailments. Other objections to the required service include reliability concerns and the unjustified curtailment priority that would be afforded to short-term customers that have not financially committed to long-term grid service. To the extent hourly firm service is required, commenters generally support use of the *IES* Method for pricing, although some commenters ask the Commission to allow pricing to vary according to regional practice. As for batching and scheduling, many parties request that the Commission clarify specific details of each of these proposals to prevent future disputes.

Mandatory Hourly Firm

1180. Various commenters state their general support of, or non-opposition to, the proposal to require hourly firm service.[714] Among those who support it, several state that they already supply the service themselves.[715] Such commenters argue that hourly firm service would decrease opportunities for undue discrimination, enhance the customer's ability to participate in the real-time energy markets, encourage trade and marketing liquidity, increase firm uses of the grid, allow greater customer choice, increase efficiencies in wholesale markets, and help maximize use of existing transmission facilities.[716] WAPA states that its experience indicates that the current provisions for preempting shorter-term transmission service with longer-term service, as codified in OATT section 13.2, adequately serve to discourage speculative hoarding of hourly capacity.

1181. Numerous commenters objecting to the proposed service cite the effect of curtailment on customers taking network or longer term service, especially in the service of native load.[717] Specifically, they argue that the inclusion of an additional short-term firm service would increase the

[712] *See pro forma* OATT section 1.18 (defining long-term firm point-to-point transmission service as service with a term of one year or more).

[713] *See IES Utilities, Inc.,* 81 FERC ¶ 61,187 at 61,833–34 (1997), *reh'g denied,* 82 FERC ¶ 61,089, *aff'd on other grounds sub nom. Wisconsin Public Power Inc.* v. *FERC,* No. 98–61,089, 1999 U.S. App. LEXIS 3998 (Feb. 23, 1999) (unpublished opinion) (adopting peak and off-peak pricing to hourly non-firm transmission service); *see also New York State Electric & Gas Corp.,* 92 FERC ¶ 61,169 at 61,593–94 (2000) (approving application of the *IES* Method for time-differentiated hourly non-firm rate design), *order on reh'g,* 100 FERC ¶ 61,021 (2002).

[714] *E.g.,* Ameren, Arkansas Commission, Bonneville, BP Energy, Constellation, FirstEnergy, MidAmerican, MISO/PJM States, Morgan Stanley, Nevada Companies, Newmont Mining, NorthWestern, Pinnacle, PPL, CREPC, and Suez Energy NA.

[715] *E.g.,* Bonneville, Pinnacle (noting Arizona Public Service Company's adoption of the service), PNM–TNMP, and WAPA (in its Desert-Southwest region).

[716] *E.g.,* Arkansas Commission, BP Energy, FirstEnergy, Morgan Stanley, Pinnacle, PNM-TNMP, and PPL.

[717] *e.g.,* APPA, Duke, EEI, MISO, and Southern.

likelihood that longer-term service would be curtailed and degrade the reliability of service to native load, since all firm service (point-to-point and network), regardless of duration, would be curtailed *pro rata*. Objecting commenters argue that such a result is unfair to customers that have made a long-term commitment to taking service, including expanding the system;[718] inconsistent with FPA section 217(b)(4), which requires the Commission to promote the availability of transmission for native load service;[719] and inconsistent with the Commission's commitment in the NOPR to maintain existing native load protections.[720]

1182. Although transmission providers plan for their native load needs when calculating ATC, Imperial argues that they cannot always accurately predict these needs. Imperial states that transmission providers have been able to rely on the release of unscheduled capacity when balancing their schedules to meet fluctuating needs (such as during heat waves). In view of the decline in transmission infrastructure relative to load throughout the country, NRECA objects to the reduction in ATC that would result from dedicating transmission capacity to hourly firm service. NRECA argues that designated network resources may no longer be regarded as such because firm transmission to support them is not available on constrained transmission systems (*i.e.*, most transmission systems). If hourly firm service is to be required, Imperial proposes also requiring transmission providers to make available all but 20 percent of non-reserved transmission as firm so that non-firm service will be available for the use of network customers and native load providers.

1183. Southern argues that the provision of hourly firm service would require the transmission provider to predict the exact hour on which expected peak conditions will occur in order to be able to post the amount of hourly firm service that will be available for each hour of a given day. If system conditions then change, Southern continues, reliability could be placed in jeopardy, which would result in long-term service being curtailed. Southern also argues that the provision of this hourly firm service would complicate real-time operations and negatively impact reliability since, if curtailments on a specific path prove necessary, it is more difficult to curtail a large number of transactions on a very short-term notice.

1184. Many argue that the justifications provided in Order No. 888 for not requiring this service remain valid, such as the argument that the service will invite cream skimming.[721] MISO sees a likelihood that an ''hourly priority war'' would ensue on constrained interfaces between firm and non-firm requests and that resolving these conflicts would be time consuming and stretch its resources. MISO argues that an hourly firm product would degrade the value of non-firm service and that the introduction of this new, logistically challenging service, further compounds the task of rooting out undue discrimination. MISO argues that the proposed mandatory introduction of this service will have serious adverse implications for many functioning RTOs. MISO contends that hourly firm service should remain strictly optional for RTOs arguing that weighing the pros and cons of this new service can best be addressed within each RTO's stakeholder process.

1185. TVA argues that hourly firm reservations would likely end up being bumped by requests for longer service (such as daily firm), consuming valuable transmission provider staff time and resources on administrative tasks with no real benefit and potentially significant costs. Similarly, Southern argues that hourly firm service would likely result in the transmission provider receiving less revenues (because fewer customers would take daily firm service) while incurring higher costs (due to implementation complexities), the net effect of which would raise OATT charges.

1186. Among commenters offering qualified support for mandatory hourly firm service,[722] ELCON and FirstEnergy ask the Commission to monitor the use of this service and to reconsider its continued need if it impairs the quality or availability of long-term firm services. Powerex argues that hourly firm point-to-point service could increase opportunities for undue discrimination unless the conditions under which the non-firm transmission service can be interrupted are clarified. South Carolina E&G argues that the Commission should give the service a lower curtailment priority than any longer term firm service (citing as support the lower reservation priority for short term firm service in section 13.2(iii)) and adopt the proposal to require that hourly firm service be scheduled the day before service is to commence.

1187. Duke explains that the current 10 a.m. deadline for firm schedules need not be enforced in the absence of hourly firm service and often is not enforced (with transmission providers acting on a comparable basis in waiving the deadline). Thus Duke identifies as a drawback to the addition of hourly firm service the likelihood that transmission providers will enforce the 10 a.m. deadline and thereby reduce existing flexibility.

1188. Some commenters objecting to the new service requirement argue that, if the Commission retains this service, certain modifications should be made.[723] These modifications include: giving the service a lower curtailment priority, pricing it at a premium above the *IES* methodology, requiring that the firm hourly postings be based upon the daily firm ATC (with the additional capacity that might be available in ''shoulder'' hours of the day being made available only as hourly non-firm), and giving secondary network service a higher priority over hourly firm. Duke argues on reply that, if the Commission determines that hourly firm service should be required, a technical conference should be held to develop appropriate, workable tariff language in light of the implementation issues raised by commenters.

Voluntary Hourly Firm Service

1189. Various commenters ask that hourly firm service not be required and, instead, continue to be allowed on a voluntary basis by willing transmission providers.[724] These commenters generally argue that the service's effect on reliability, curtailment priority, longer term service, transmission expansion, and the ability to serve native load counsels against mandating the service. NRECA argues that hourly firm service would unduly interfere with the ability of network customers (and the transmission provider on behalf of its native load customers) to use secondary network service, which is offered only on an ''as available'' basis and therefore would have a lower reservation and curtailment priority than hourly firm service.

1190. NRECA notes that the Western Interconnection, where hourly firm service has proven to be a useful product, differs from the Eastern

[718] *e.g.,* MISO and Southern.

[719] *e.g.,* APPA, NRECA, and Southern.

[720] *e.g.,* Southern.

[721] *e.g.,* LDWP, MISO, Southern, TAPS, TDU Systems.

[722] *E.g.,* ELCON, FirstEnergy, Powerex, and South Carolina E&G.

[723] *e.g.,* APPA, NRECA, Southern, and TAPS.

[724] *E.g.,* APPA, Duke, East Texas Cooperatives, EEI, Imperial, LDWP, LPPC, Northwest IOUs, NRECA, PJM, Southern, and TDU Systems.

Interconnection in a number of respects, in particular, by virtue of extensive reliance on point-to-point service by LSEs to serve native load. For this reason, NRECA continues, public utility transmission providers should only be allowed to voluntarily offer hourly firm transmission service if the service is available equally to all transmission customers and the new service does not undermine the quality of, and flexibility of, the transmission provider's existing network service (including secondary network service) and point-to-point transmission service. NRECA also requests that the Commission clarify that the only circumstance in which hourly firm service could be offered would be if daily service were not being fully used.

1191. Northwest IOUs suggest that the Commission develop standardized point-to-point hourly firm service provisions for the voluntary provision of this service by those transmission providers that determine such service would be appropriate to offer on their systems. TDU Systems argue that the Commission should condition approval of an hourly service on requirements that a lower curtailment priority is established for hourly firm service than other firm services, including secondary network service; and, it may only be sold in the hour preceding the start of service to ensure that hourly service would not impede the provision of service to other firm services, including secondary network service. In light of comments, Powerex abandoned its initial conditional support for the proposal to support voluntary provision of the service.

Alternative Proposals

1192. PJM recommends adding a service similar to PJM's non-firm willing to pay congestion (NF–WPC) service which may serve the same purpose as, and be an alternative to, hourly firm service. NF–WPC service would be evaluated for ATC and curtailed by transmission customers if the effective price of congestion were too high. Thus, NF–WPC service will result in a reduction in all TLR curtailments. To add this service to the OATT, PJM explains, all transmission providers with control over dispatch would have to provide a transparent means for redispatch to clear congestion and maintain reliability on either side of a border.

1193. Xcel argues that it is possible that hourly firm service would not be needed if the existing OATT were clarified as it relates to priority of non-firm service. Xcel proposes that the Commission could clarify that non-firm service is not interruptible during the hour due to other non-reliability driven requests, but rather at the start of the next hour, provided sufficient scheduling notice is given. Xcel continues that this clarification would also stipulate that non-firm service (and all other types of service) may be curtailed without notice at any time for reliability reasons.

Pricing

1194. Many commenters support the Commission's proposal to use the *IES* Method to price hourly firm service.[725] Several commenters suggest that the Commission allow transmission providers to define their own peak and off-peak hours under the *IES* methodology, with some suggesting that it should be allowed as a regional variation to account for the different peak times in regions such as the WECC.[726] East Texas Cooperatives asks the Commission to require that revenue from hourly firm service be applied as a credit to network service revenue requirements like other point-to-point services. PGP supports the *IES* Method, but recommends that the Commission be open to other approaches.

Reservations, Scheduling, Preemption and Right of First Refusal, Batching

1195. Some commenters support the proposed reservation or scheduling requirements for hourly firm service.[727] Others commenters express concerns regarding, or object to, this aspect of the hourly firm proposal.[728] As discussed below, several commenters suggest modifications to different components of the proposal.

1196. Some commenters state that hourly firm should be a means of selling unused capacity in hours not purchased for longer-term transactions and, as a result, it will be important to establish a sequencing for sales that accomplishes this so that cream skimming does not occur.[729] Tacoma recommends that the Commission establish hourly firm service as the lowest priority in the service request queue. Tacoma also suggests that the Commission limit the purchase of hourly firm in such a way as to assure that the purchase is not an attempt to manipulate a market, such as making the service available only to LSEs, which Tacoma states would ensure that capacity is utilized to meet a real market need.

1197. SPP urges the Commission to apply the same reservation deadline to hourly firm as used for daily firm service in order to make the service easier to administer (and limit the impact on non-firm service). Bonneville also suggests that reservation timing requirements be the same as those for hourly non-firm service and, with respect to competing reservations, hourly firm service be classified as Short-Term Firm. TVA notes that although the scheduling deadline for service is 10 a.m. the day before service is to commence, the NOPR also states that longer-term requests may preempt shorter requests until one hour before the commencement of service. TVA sees an inconsistency in that it appears firm service can be reserved and scheduled after 10 a.m. on the day prior all the way up until one hour before the service is to commence. TVA argues that no service that could preempt the hourly service should be sold after the 10 a.m. day-ahead deadline, and requests that the Commission clarify this ambiguity.

1198. If the Commission requires hourly firm service, Progress Energy requests that it be offered on a day-ahead basis only, as proposed in the NOPR, to allow transmission providers sufficient time to analyze the reliability impacts of the requested hourly firm service. Nevada Companies recommend that any hourly firm service have the same scheduling deadlines as daily firm and that customers not be permitted to submit hourly firm schedules throughout the day. In Nevada Companies' view, this would enable transmission customers to schedule firm transmission only for the part of the day that it is needed while, at the same time, transmission providers would not be overwhelmed with the task of administering the reservation process.

1199. Some recommend that scheduling conform to the existing scheduling practices in each region, such as in the WECC.[730] For its part, MISO argues that the proposed scheduling deadline for hourly firm service is before the deadline for the submittal of the MISO daily firm service, which would require a substantial change to its Energy Markets Tariff, firm service evaluation process, and other firm and non-firm timing requirements. MISO argues that this could adversely affect the current Joint and Common Market Alignment of Business Practices initiative with PJM. Public Power Council offers

[725] *E.g.,* Ameren, EEI, NorthWestern, PGP, and PNM–TNMP.

[726] *E.g.,* Northwest IOUs, Public Power Council, and CREPC.

[727] *E.g.,* Ameren, Duke, NorthWestern, PNM–TNMP, and WAPA.

[728] *E.g.,* Bonneville, Southern, and TVA.

[729] *E.g.,* Public Power Council and Tacoma.

[730] *E.g.,* MidAmerican, Northwest IOUs, Public Power Council, and CREPC.

Bonneville's scheduling timeline as an example in which longer blocks get priority over the shorter blocks within the 10 a.m. to 2 p.m. preschedule-day reservation period, and hourly firm is bought within the day at the same times as hourly non-firm transmission (*i.e.*, up to 20 minutes prior to the delivery hour).

1200. Occidental requests that the Commission change the 10 a.m. day-before scheduling timeline to be as close to real-time as possible. It contends that under the *pro forma* OATT, merchant generators still will be relegated to making non-firm reservations and sales, because the 10 a.m. prior day firm service scheduling timeline would cause them to incur expensive reservations to the sales point, but not be able to have the transaction tagged with source and sink (as required under the NERC tagging procedure), before consummation of the firm hourly transaction. Occidental further contends that the change in scheduling timeline will not be problematic to the transmission providers, particularly if the transaction takes place in a single control area. Occidental also argues that the OATT benefits the transmission provider, which can favor its own or affiliated generation when balancing with other control areas and dispatching in real time.

1201. Bonneville, which has provided hourly firm service since 2002, takes issue with the fact that the Commission proposes that the service would become unconditional only one hour before the commencement of delivery. Bonneville argues that its own timeline, under which hourly firm service becomes unconditional at the close of the preschedule window for the day of delivery (currently, at 2 p.m. of the preschedule day or as soon as practicable thereafter), is superior and should be adopted by the Commission. Bonneville explains that, in its experience, customers place great value on having unconditional firm rights before they reach the real-time scheduling window, and an hour leaves little or no time to make alternative arrangements if the hourly firm reservation is preempted. Finally, Bonneville foresees potential reliability effects if a customer using hourly firm transmission for operating reserves is preempted the hour before delivery, and is unable to make transmission arrangements elsewhere.

1202. Ameren argues that a later request for hourly firm service should not be able to preempt an earlier request, even if it is for a greater number of hours. According to Ameren, this will provide certainty to users of this service since they will know they will not be bumped by other customers using the service.

1203. Duke requests guidance on how long the hourly firm customer has to respond to a competing request. Since hourly firm could be preempted up to an hour before the schedule starts, Duke argues that in many cases there will not be 24 hours available and the scheduling deadline (of 10 a.m. of the day prior to commencement of such service) may have passed. For example, if a pre-confirmed, longer-term, competing request is received just prior to the deadline (one-hour prior to service commencing), Duke questions whether the transmission provider is required to offer the right of first refusal at all.

1204. Joined by TranServ, Duke also requests that the Commission provide guidance on how to administer the right of first refusal when, for example, three different hourly customers have confirmed reservations on a constrained interface for different hours in a day and the transmission provider then receives a pre-confirmed request for daily service on the same path for the same day. Alternatives solutions for this scenario offered by Duke include offering the shorter-term customers simultaneous or consecutive opportunities to exercise the right of first refusal, prohibiting the preemption of multiple overlapping requests, or denying shorter term customers a right of first refusal. Duke recommends NAESB develop appropriate business practice standards after the Commission's decision on this issue.

1205. With the NOPR's potential for adding more complexity with hourly firm service under similar conditions as other short-term firm services, TranServ requests that the Commission either eliminate the conditional nature of short-term firm point-to-point service under the OATT (and the reservation window would be set to not interfere with requests for daily firm service) or allow hourly firm service to be preempted without a right of first refusal.

1206. Duke requests that, whether or not the Commission requires hourly firm service, the Commission clarify how the ''short-term rights of first refusal'' should be implemented in section 13.2(iii) of the OATT, since there already is some lack of clarity with regard to this right for daily, weekly, and monthly service.

1207. Based on its experience, WAPA suggests that the Commission institute limits on the allowable time period in which customers may contact the transmission provider for the purpose of withdrawing an hourly firm request in order to avoid potential ''gaming'' issues that may arise from entities requesting transmission on a pre-scheduled basis and then asking for the request to be withdrawn during real-time. To simplify real-time administration of hourly firm service, WAPA suggests that the Commission explicitly include in the revised *pro forma* OATT a statement waiving the Order No. 638 displacement rules for hourly requests during the hour before the service is to commence.

1208. Several commenters support the Commission's batching proposal.[731] WAPA argues that the proposed limitation on batching hourly firm requests and schedules to within the same day would alleviate the workload issues associated with evaluating individual hourly firm reservations in order to identify conflicting schedules across congested paths.

1209. MidAmerican objects to the batching proposal, arguing that transmission requests should be evaluated in queue order and schedules linked to a specific OASIS request. MISO argues that the batching proposal may interfere with the established protocols for transmission service request processing. In MISO, for example, there is no interface for Available Share of Total Flowgate Capability, which would seem to suggest that batch processing could infringe on the various Commission-approved seams agreements.

1210. Some commenters offer modifications or request clarifications. Bonneville proposes that NAESB develop industry standards for defining and processing batched reservations and schedules. EEI argues that transmission providers who offer hourly firm service should permit their customers to batch multiple requests for service that have the same points of receipt and delivery; are for the same quantity of service, and are for the same day. Otherwise, EEI explains, batching will complicate the ability of the transmission provider to study requests for hourly service. NorthWestern explains that it cannot fully support the Commission's recommendation to allow ''batching'' of requests without a more clear definition of what may be batched and a determination that requests of a longer increment preempt shorter increment requests (*e.g.*, a request for daily service preempts a request for hourly service) regardless of how many hours are batched together.

1211. TranServ states support for the ability to batch requests and schedules for multiple hours of firm service with

[731] *E.g.*, PGP, PNM–TNMP, and WAPA.

varying capacity over the hours. However, with respect to competing requests and the right of first refusal, TranServ suggests that the preempting request must be for a fixed capacity over the term of the request to be considered a competing request. According to TranServ, this would prevent potential gaming by a customer submitting a request for one extra hour at 1 MW to gain priority over another reservation.

Commission Determination

1212. In light of the potential for market disruption and the scheduling complications that would arise from providing hourly firm service, we decline to adopt in the Final Rule the proposal to require transmission providers to offer hourly firm service. While there is some industry support for hourly firm service, we conclude that the downsides associated with requiring transmission providers to offer hourly firm service outweigh the benefits of the proposal due to the significant issues raised by commenters. Commenters 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 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 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

[732] Order No. 888 at 31,665 n.176.

[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.

[736] *Id.*

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

existing transmission customer match competing offers as to term and rate. The Commission 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 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 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, believes 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's 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's 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

[738] *E.g.,* APPA, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, EEI, 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.

[739] *See also* TDU Systems Reply.

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

aggregated loads of several small customers can have a substantial impact on the system. EEI contends that TAPS's 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]

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.

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 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 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

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

[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.

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

[745] *E.g.*, EEI Reply and Southern Reply.

[746] *e.g.*, Morgan Stanley and Manitoba Hydro.

[747] *e.g.*, Alberta Intervenors, TransAlta, and Williams.

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 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 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

[748] *See also* Morgan Stanley.

[749] *See* EPAct 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.''

[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.

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 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 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

[751] *E.g.*, Ameren, Barrick Reply, Bonneville, Community Power Alliance, Constellation, Dominion, Duke, East Texas Cooperatives, EEI, 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.

[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.

transmission customers to bear the increased costs associated with the newly constructed transmission facilities. EEI proposes that a date be included in the initial service agreement by which the transmission customer must exercise its rollover rights if upgrades are needed to accommodate the rollover. If there is a pre-confirmed competing request or newly projected growth in native load, EEI suggests that the rollover customer must exercise its rollover and match by the later of the project start date for any new transmission facilities needed or 60 days after the transmission provider notifies the transmission customer of the competing request.[753] Additionally, if more than one-year notice is required because of the need for upgrades, EEI proposes that the transmission provider be required to notify the transmission customer if subsequent events delay the project start date, in which case the notice period would be revised. EEI asserts that any disputes can be dealt with by protesting the filing of an unexecuted agreement. EEI stresses that better, more inclusive planning, and more transparent ATC calculations, will provide transmission customers with greater assurances that project start dates are accurate.

1242. Southern suggests that partial rollover be permitted if notice is not given in time for construction of an upgrade needed to provide full service. Duke, Nevada Commission, and Southern suggest that providing for one-year notice without a link to the start date for any upgrades falls short of the native load protections found in section 217 of the FPA. As an alternative, the Nevada Commission suggests tying the notice requirement to the amount of capacity subject to rollover, *i.e.*, below a certain threshold, one year would be deemed *per se* sufficient.

1243. APPA argues in reply that many customers may not know even one year in advance if they will have firm power supplies under contract that would enable them to roll over their corresponding firm transmission agreement and, therefore, requiring them to exercise their rollover rights even earlier in the contract term would only exacerbate an already impossible situation. In their replies, NRECA, TAPS, TDU Systems, and Utah Municipals urge the Commission to reject the recommendation that notice periods be expanded to be commensurate with construction lead times. They argue, among other things, that LSE transmission customers need a reasonable amount of certainty so that they may plan their power supply arrangements without fear that they may become unraveled due to unforeseeable circumstances. Utah Municipals also assert that the proffered justification for the proposal—to prevent overbuilding—is questionable at best as even the current policy which requires only a one-year contract minimum for rollover and 60-days notice has not resulted in wasteful overbuilding of the system. TDU Systems also point out that under section 28.2 of the *pro forma* OATT, transmission providers should be planning and expanding their systems to accommodate their network customers' current and future needs.

1244. The one-year notice provision is opposed by several commenters, who argue that having to give one-year notice constitutes an undue burden.[754] In general, these commenters argue that under current market conditions, transmission customers do not typically renew supply contracts one year in advance of expiration.[755] Alberta Intervenors argue that a one-year notice provision does not aid in re-marketing capacity, as any unused long-term firm service is already re-marketed as short-term firm or non-firm service. Alberta Intervenors also argue that the increased lead time increases risk and creates uncertainty making it less likely that customers will enter into long-term contracts. EPSA and Exelon suggest a flexible notice rule that depends on the length of the underlying contract or requiring more than 60-days notice if there is insufficient capacity for a new long-term firm transmission service request, as is done in PJM. They also suggest PJM's approach whereby a transmission customer must inform PJM whether it will roll over within thirty days of being notified of a competing request. PPM and Wisconsin Electric suggest a six-month notice period, which complements their alternative suggestion of a three-year minimum contract term.

Commission Determination

1245. The Commission finds that the current 60-day notice period should be modified to reflect the longer term (five years) of the rollover rights. Currently, a customer with a one-year rollover right has 60 days to provide notice of whether it intends to rollover its capacity. This 60-day period was reasonable for a rollover right of short duration (one year), but it is no longer reasonable for a rollover right with a minimum five-year term.

1246. In selecting a new notice period, the Commission has attempted to balance the circumstances faced by customers in renewing power supply contracts and the interests of transmission providers in attempting to plan their system. The Commission recognizes that no single notice period can perfectly balance these considerations, but chooses the one-year notice period as most appropriate under the circumstances. Given that the minimum rollover term has been lengthened to five years, it is reasonable to expect that customers will consider renewing such long term obligations in advance of 60 days prior to the expiration of their current obligation. We do not believe it is reasonable to fashion our notice period for customers that wait until the last minute to evaluate whether to extend their long-term contracts.

1247. Many transmission providers argue that a one-year notice period is too short because it is not consistent with the transmission provider's planning horizon. We disagree. The Commission is extending the minimum term for rollover rights to five years to ensure greater consistency between the customer's rights and obligations and the planning and construction obligations of the transmission provider. We believe that this modification satisfies the principal concerns of transmission providers regarding the current policy on rollover rights. We recognize that a one-year notice period is shorter than the typical planning horizon, but we decline to extend the notice period to a time that coincides with the typical planning horizon or the time it takes to construct new facilities. Doing so would effectively eliminate rollover rights altogether, given that the resulting notice period could be three-to-five years. We do not believe it is reasonable to expect customers to have decided on new sources of supply three years in advance of the expiration of their current contracts. We therefore find that a one-year notice period most appropriately balances the interests of customers and transmission providers.

c. Matching and Rollover Restrictions Based On Native and Network Load Growth

Comments

1248. As noted above, the Commission proposed to maintain the requirement that an existing rollover

[753] Ameren, Pinnacle, Southern, and TranServ agree that the submission of a competing request should trigger an accelerated timeline for the original customer to exercise or release its rollover rights.

[754] *E.g.*, Alberta Intervenors, Alcoa, Arkansas Municipal, EPSA, Exelon, Manitoba Hydro, Morgan Stanley, PPM, TransAlta, Williams, and Wisconsin Electric.

[755] *E.g.*, Arkansas Municipal, Williams, and Wisconsin Electric.

transmission customer match competing offers as to term and rate. Some commenters argue that a competing customer be required to execute a contingent service agreement that becomes effective if the rollover customer does not match.[756] Given the increase in the minimum contract term to five years in order to be eligible for a rollover right, TAPS argues that matching must be structured to recognize that a network customer must extend its power supply by at lease five years as well, in order to match a competing point-to-point customer that can simply extend its reservation. To ensure that network customers are not disadvantaged by matching, TAPS suggests that the Commission restrict reservations qualified to compete against a network customer's reservation to customers with long-term power contracts, so they are on more equal footing with network customers. TAPS also proposes a cut-off for requests with which the network customer will need to compete, such as three months prior to when the network customer exercises its rollover right, so that the network customer can structure its power supply commitments with some degree of advance knowledge of the competing requests. In its reply, Bonneville suggests allowing network transmission customers to compete based on the duration of their network transmission service request rather than on the duration of their resource commitments. As such, the transmission provider would assume that existing designated resources would continue to be used after the rollover unless informed otherwise.

1249. The Commission also discussed in the NOPR 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. Several commenters argue that a transmission provider's native and network loads should not be forced to compete with other transmission customers, as opposed to allowing the transmission provider to continue to reserve capacity for its native and network load at the time of granting a rollover.[757] Most also stress that requiring a transmission provider to compete would violate the native load protections in section 217 of the FPA. LDWP contends that there should be no limitation on a transmission provider's right to recall capacity based on revised forecasts of native load growth.

1250. APPA contends on reply that transmission customers could find it very difficult to line up a new firm power supply of a term long enough to match the power supply arrangements of its vertically-integrated investor-owned transmission provider (which is likely to have owned, rate-based generation in its power supply portfolio and, therefore, could agree to a very long-term transmission agreement). TDU Systems argue that transmission providers should be forced to compete for capacity and that this is, in fact, required by section 217 of the FPA, as the native load preference does not distinguish between the retail native loads of transmission providers and the native loads of other LSEs dependent on their systems. Powerex and PPM also support requiring transmission providers to compete. NorthWestern and Southern support requiring transmission providers to compete, but only when a restriction is not included in the original agreement. APPA also notes in its reply comments that, if Southern included LSEs' loads in its transmission planning and construction program along with its own native load, there would be no need to reclaim the LSEs' capacity at the close of the initial contract term or the renewal terms.

1251. Several commenters also addressed the Commission's request 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. Many of these commenters support the development of a clear and transparent method for demonstrating native load growth.[758] Some commenters point to the need for accurate and transparent ATC calculations to aid in this process.[759] If the transmission provider's calculation of ATC is consistent with the requirements the Commission adopts in this proceeding yet there is insufficient capacity to accommodate the customer's rollover, EEI recommends that the provider may include in the service agreement a limitation of rollover rights. AWEA recommends that transmission providers adopt the same transparent and consistent methods used to compute the Existing Transmission Capacity component of ATC to develop native load growth reservations that support rollover restrictions. AWEA, NorthWestern, and TAPS suggest posting forecast information on the OASIS, and TAPS goes on to stress that this information should be included in state planning documents as well as the transmission provider's coordinated and regional planning process. EPSA stresses that native load capacity must follow native load and not only be made available for the transmission provider and its affiliates. EPSA believes this is required by the native load protections found in FPA section 217.

1252. Duke asks the Commission to address the possibility that capacity subject to a rollover right might be needed to serve native load outside of the ten-year planning horizon. The Nevada Commission and Southern suggest that the Commission give deference to state resource planning processes in attempting to verify native load growth forecasts. Southern also asks that the Commission clarify that rollover rights can be restricted based on rollover rights belonging to higher-queued transmission customers. If transmission studies show no problems without the presence of a rollover, but then problems are identified with the rollover included, Southern contends that placing a corresponding limitation in the service agreement would be appropriate. Pinnacle requests clarification that when rollover rights are restricted based on native load growth, the transmission customer must pay for upgrades to continue its service.

1253. Several commenters also suggest that transmission providers should be permitted to evaluate rollover restrictions at the time of each rollover.[760] These commenters argue that it is impossible to identify all potential limitations upfront as system conditions change in unforeseeable ways (*e.g.*, fluctuations in fuel prices can change dispatch decisions). They also argue that allowing a re-evaluation is consistent with the native load protections in FPA section 217.

1254. In its reply, TAPS argues that a transmission provider should not be permitted to avoid its planning and expansion obligations by treating load growth not anticipated and documented in the original service agreement as a competing request to be matched. TAPS points out that section 217 of the FPA treats all LSEs—whether they are transmission providers or transmission-dependent utilities—the same, without

[756] *E.g.*, MidAmerican and Powerex.

[757] *E.g.*, Allegheny, Entergy, FirstEnergy, Imperial, Nevada Companies, Progress Energy, Salt River, Santa Clara, and Seattle.

[758] *E.g.*, AWEA, Duke, EEI, Entergy, EPSA, Imperial, Nevada Commission, Powerex, Salt River, Seattle, South Carolina E&G, Southern, SPP Reply, and TAPS.

[759] *E.g.*, AWEA, EEI, EPSA, and MISO.

[760] *E.g.*, Nevada Companies, South Carolina E&G, and Southern.

distinction, and therefore provides no basis to allow one LSE to claim transmission rights currently used by another LSE.[761] Lastly, TAPS argues that when a provider is reclaiming capacity for load growth reserved in the initial service agreement, rollover customers should be allowed to match the request, thereby imposing an additional requirement on the provider.

Commission Determination

1255. The Commission will not adopt any changes to its matching policies at this time. At the time of rollover of their contracts, transmission customers will continue to be required to match competing requests for service as to term and rate in order to roll over their service. This preserves the current policy goal of providing a mechanism for awarding capacity to those who value it most, as well as providing for a tie-breaking mechanism when needed that gives priority to existing customers so that they may continue to receive transmission service.[762] Absent the requirement that the customer match the contract term of a competing request, transmission providers could be forced to enter into shorter-term arrangements that could be detrimental from both an operational standpoint (*i.e.*, system planning) and a financial standpoint.[763] We clarify, however, that transmission customers must also enter into a transmission contract of at least five years in order to obtain a subsequent rollover right in the absence of a competing request for a longer term.

1256. The Commission will continue to require rollover restrictions based on reasonable forecasts of native load growth or preexisting contracts that commence in the future to be included in the initial transmission service agreement. This will remain the only appropriate way to restrict a rollover right. We also will continue to evaluate a transmission provider's native load growth forecasts on a case-by-case basis, as no commenter has provided us with a sufficiently clear, consistent, and transparent method that could be implemented on a generic basis that ensures that the demonstration of native load growth is accurate and is tied to a need for the specific capacity reserved by a rollover customer.[764] Because we will continue to require rollover restrictions to be included in the initial transmission service agreement, we necessarily reject the suggestion that transmission providers be permitted to restudy for rollover restrictions at the time of each rollover. Accordingly, it is unnecessary for us to address whether it would be appropriate for a transmission provider's native or network load to compete with a rollover customer if a new study at the time of the rollover indicated a native or network need for the capacity.

1257. In response to the suggestions of some commenters, we believe that consideration should be given in our case-by-case evaluations of native load growth forecasts to state-approved integrated resource plans that show a native load need for the capacity.[765] Moreover, we believe that the ATC and planning reforms that we are adopting in this Final Rule will provide greater transparency and assurance that transmission providers' forecasts of native load growth are accurate. We emphasize that we expect the forecasts utilized in transmission planning to be consistent with the forecasts utilized to support a rollover restriction. Lastly, the coordinated and regional planning process required by this Final Rule is designed to improve the availability of transmission service by, among other things, increasing transparency and providing customers a meaningful opportunity to participate in the planning process. Accordingly, we believe that improved planning should help to reduce the need to restrict rollovers in the future.

d. Other Issues

Comments

1258. A number of comments relate to the applicability of the rollover-related reforms to RTOs and ISOs. CAISO asks the Commission to confirm that the rollover reforms do not apply to CAISO as its current tariff does not have such a provision and rollover is, in fact, incompatible with CAISO's transmission service model. Sacramento, however, asks the Commission to clarify that rollover rights apply to long-term firm service provided by RTOs and ISOs under Order No. 681 under what it terms the ''as good as or superior to'' standard.[766] Organization of MISO and PJM States assert that any changes for RTOs should be made through the stakeholder process. In its reply, Williams opposes permitting RTO stakeholders to determine changes in rollover rights policy in RTO regions, as it would result in disparate rules and practices and increased opportunities for discrimination, and therefore, the Commission should adopt a single policy applicable to all rollover rights.

1259. Other commenters raise different discrete issues. Morgan Stanley asks the Commission to amend *pro forma* OATT section 2.2 to include existing policy determinations with respect to the manner in which a transmission provider can curtail or, alternatively, must honor and accommodate rollover requests. Duke asks the Commission to abandon its existing policy prohibiting the restriction of rollover rights based on the potential exercise of other customers' rollover rights. Salt River asks the Commission to clarify that the proposal to extend the minimum term to five years does not change the definition in section 1.20 of the *pro forma* OATT that one year constitutes a long-term contract. AWEA, Constellation, and EPSA ask the Commission to allow transmission customers to waive their rollover rights.

Commission Determination

1260. As we explain in section IV.C above, RTOs and ISOs must submit a filing showing that their practices are consistent with or superior to the modifications made in the Final Rule. This does not necessarily mean that entities such as CAISO must create rollover rights if they do not have them already. Arguments regarding the applicability of rollover reform may be raised pursuant to the process described in section IV.C. We also clarify that our decision to extend the minimum term to five years does not change the definition in section 1.20 of the *pro forma* OATT that one year constitutes a long-term 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

[761] *See also* APPA Reply and TDU Systems Reply.

[762] *See* Order No. 888–A at 30,197.

[763] *Id.*

[764] While the Commission has not to date accepted any native load growth showing made by a transmission provider, it has recently set for hearing several such showings. *See, e.g., Southern Co. Servs., Inc.*, 116 FERC ¶ 61,050 (2006); *Nevada Power Co.,* 116 FERC ¶ 61,093 (2006).

[765] We note that this is consistent with the Commission's evaluation of rollover restrictions proposed by transmission providers in the past. *See, e.g., Nevada Power Co.*, 97 FERC ¶ 61,324 at 62,493 n.17 (2001).

[766] In its reply, CAISO argues that this request to expand the requirements of Order No. 681 is inappropriate both because the Commission and courts have already recognized that rollover rights under the *pro forma* OATT do not apply to entities like CAISO that do not offer traditional Order No. 888 network and point-to-point transmission services and because the Commission has already rejected such a requirement in Order No. 681 itself.

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 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 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 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

[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.

[769] *E.g.*, Northwest IOUs, Duke Reply and EEI Reply.

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

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.

1269. In Order No. 676, the Commission adopted the ''Standards for Business Practices and Communication Protocols for Public Utilities'' developed by the NAESB's Wholesale Electric Quadrant (WEQ).[771] Order No. 676 incorporated the aforementioned standards by reference into the Commission's regulations, required public utilities to implement the standards by July 1, 2006, and required public utilities to file revisions to their OATTs to include these standards.[772] The WEQ Standards include a number of standards addressing requirements for dealing with redirects on both a firm and non-firm basis.[773] All of the WEQ Standards dealing with redirects were adopted by the Commission in Order No. 676, except for WEQ Standard 001–9.7, which addresses the impact of a firm redirect on a long-term firm transmission customer's rollover rights under section 2.2 of the *pro forma* OATT. The Commission directed the WEQ to reconsider WEQ Standard 001–9.7 and to adopt a revised standard consistent with the Commission's policies.[774] The Commission also offered guidance to assist the WEQ in developing a standard that is consistent with Commission policy.[775]

NOPR Proposal

1270. In response to the NOI, commenters raised various concerns regarding redirects. Among other things, customers complained of difficulties obtaining redirected service, while transmission providers complained of a lack of clarity in the rules governing redirects. In the NOPR, the Commission stated its belief that a number of these concerns appeared to have been resolved by the adoption of the WEQ Standards in Order No. 676, which was issued after the NOI. The Commission sought comment on whether parties believed the WEQ Standards in fact addressed those concerns adequately.

1271. The Commission also stated its expectation that a number of other concerns raised in response to the NOI, while perhaps not yet addressed (or addressed fully) by a WEQ Standard, are nevertheless the types of issues that are appropriate for the WEQ process. The Commission therefore proposed that each commenter that continued to believe additional reform is necessary with regard to redirects evaluate whether its concerns would more appropriately be addressed by the WEQ as it considers its next version of its standards.[776] The Commission noted that WEQ was in the process of reevaluating WEQ Standard 001–9.7, dealing with redirects and rollovers, so that it is consistent with the Commission's guidance given in Order No. 676. The Commission requested comment on whether the WEQ process, along with the guidance provided by the Commission in Order No. 676, is sufficient to address the concerns of commenters that seek clarification on the interplay between redirects and rollovers.

1272. In the NOPR, the Commission acknowledged that there were additional, more fundamental concerns with regard to section 22 raised in response to the NOI. Customers generally argued that their ability to redirect to new points is stymied by a lack of ATC at the new points or the need for major upgrades, or that transmission providers take too long to process the redirect request. Transmission providers, on the other hand, complained of the administrative burdens and complexity (particularly with regard to reliability) of processing transmission customers' short-term changes in service and that there is often not enough time for the market to respond to capacity made available on a customer's original path. The Commission stated its belief that other proposed reforms in the areas of process, transmission planning, and ATC calculation should address transmission customer concerns regarding redirects. The Commission encouraged interested parties to submit a specific proposal, along with proposed revised *pro forma* OATT language, to the extent they believe the proposed reforms will not adequately address their concerns.

1273. The Commission also noted in the NOPR that several transmission providers had posted business practices that allow network customers either to substitute an off-system non-designated resource for a designated resource or to redirect the point of receipt associated with an existing network resource. The Commission proposed that network customers not be permitted to redirect network transmission service because network service involves no identified contract path and therefore should not be treated as a directable service.

a. Proposed Reliance on WEQ Process and Other OATT Reforms

Comments

1274. Commenters generally agree with the Commission that issues with respect to redirects of firm and non-firm transmission service are best addressed through the WEQ as established by NAESB, in accordance with Order No. 676 and the WEQ process for creating new standards.[777] Seattle argues that the NAESB standard setting process has worked well thus far and, as a result, other redirect issues should be first referred to NAESB as a standard-setting request. MISO states that it has serious concerns with the WEQ process and the Commission's unwarranted deference to NAESB to develop what will become binding business standards and practices.

1275. Nevada Companies recommend the following improvements for the NAESB process: use of a professional facilitator to keep discussions focused and moving; and mandatory surveys breaking down the sections on proposed NAESB standards after the first round of comments are received to determine if consensus exists on the proposed standards, since it appears that there are relatively few participants at NAESB meetings where standards are being drafted and relatively few commenters on those draft standards.

1276. Several commenters state that they agree with the Commission's proposal to rely on other proposed

[771] The WEQ was established by NAESB in response to a Commission order requesting the wholesale electric power industry to develop business practice standards and communication protocols by establishing a single consensus, industry-wide standards organization for the wholesale electric industry. *See* Order No. 676 at P 3–4.

[772] The standards will hereinafter be referred to as the WEQ Standards. The Commission adds a reference to the WEQ Standards in section 4 of the *pro forma* OATT, which identifies the Commission's regulations containing the terms and conditions relevant to the OASIS and standards of conduct.

[773] The requirements for dealing with redirects on a firm basis are found at WEQ Standard 001–9, *et seq.*, and the requirements for dealing with redirects on a non-firm basis are found at 001–10, *et seq.*

[774] Order No. 676 at P 52.

[775] *Id.* at P 53–61.

[776] The Commission noted in this regard that the WEQ's procedures ensure that all industry members can have input into the development of a business practice standard, whether or not they are members of NAESB, and each standard it adopts is supported by a consensus of the five industry segments: transmission, generation, marketers/brokers, distribution/load-serving entities, and end-users. *See* Order No. 676 at P 5 & n.5.

[777] *E.g.*, EEI, Imperial, NorthWestern, Southern, and Suez Energy NA.

reforms in the NOPR to resolve the remaining redirect issues.[778] Seattle generally agrees that the reforms proposed in the NOPR should improve the ability to assign and use transmission on a firm basis. EEI and NorthWestern state that the NOPR proposal to increase transparency in the calculation of ATC should assist transmission customers in both selecting transmission paths that may be available for redirect and understanding why certain paths cannot accommodate redirect transactions.

Commission Determination

1277. The Commission concludes that the proposed method for addressing remaining concerns with redirects—*i.e.*, relying on other reforms adopted in this Final Rule and in the Order No. 676 proceeding—is adequate to ensure that transmission providers do not engage in undue discrimination when a customer seeks to modify its receipt and delivery points on a firm basis. As explained throughout this Final Rule, the reforms adopted herein address the remaining opportunities for undue discrimination. Planning and ATC reforms will give transmission customers more accurate and complete ATC information when evaluating their redirect options. Increased transparency will give transmission customers the information they need to evaluate a transmission provider's denial of a request to redirect. Modifications to the process for requesting and securing firm point-to-point service will improve the ability to redirect transmission service to new points pursuant to section 22 and ensure complete and timely responses from transmission providers. The Commission therefore concludes that no further reforms specific to redirects are necessary at this time.

1278. The Commission also concludes that the NAESB WEQ is the appropriate standard-setting body for developing business practices and implementing the Commission's redirect policy. The Commission will refrain from commenting here on the NAESB process itself because we believe that the industry is best situated to determine how to structure the standard-setting process to provide for the widest possible participation and consensus. We nevertheless clarify that, consistent with precedent, NAESB is charged with implementing Commission policy through business practices.[779] The Commission finds that the NAESB WEQ is an acceptable standards development process, representing a cooperative effort by industry participants to develop business practices that enhance the efficiency of the electric grid.[780] Where necessary, NAESB participants may seek clarification of Commission policy so that NAESB may develop the appropriate standards.

b. Redirects and Rollovers Rights

Comments

1279. Regarding the interaction between redirects and rollovers, some commenters request that the Commission clarify what they view as an inconsistency between Order No. 676, the Commission's existing *pro forma* OATT, and the rollover proposal in the NOPR. Specifically, Bonneville, MISO, and Southern argue that, contrary to the *pro forma* OATT and NOPR, Order No. 676 improperly suggested in an example that a short-term redirect of a long-term service agreement gives the customer rollover rights for the new path. TranServ supports placing the following two conditions on the receipt of rollover rights for redirects: a redirect on a firm basis must be for one year or longer, and the redirect must be for the entire remaining term of the parent (original) request.[781] If these conditions are met, TranServ contends that the customer will be granted rollover rights on the redirect path and lose the rollover rights held on the original path. If the customer wishes to retain rollover rights on the original path, TranServ continues, it will have the option to submit multiple redirect requests of less than one year in duration for the term desired. With respect to WEQ Standard 001.9.7, MISO incorporates by reference its opposition to the Commission's adoption of the proposed transfer of rollover rights on the redirected path in its request for rehearing of Order No. 676. There MISO argued that there should be no rollover rights on a redirect path and that the guidance in Order No. 676 requiring the transmission provider ''to offer rollover rights to a customer requesting a firm redirect if rollover rights are available on the redirect path'' was inconsistent with the *pro forma* OATT.

Commission Determination

1280. Commission policy allows a redirect of firm, long-term service to retain rollover rights, even if the redirect is requested for a shorter period. In other words, the rollover right follows the redirect, regardless of the duration of the redirect. Contrary to the comments of Bonneville, MISO, and Southern, the Commission did not impose this requirement for the first time in Order No. 676, but merely provided guidance to the industry by restating Commission policy on this matter. The Commission has explained in prior orders that a transmission customer making a firm redirect request does not convert its original long-term firm transmission service to short-term service, nor does it lose its rollover rights under its long-term firm transmission service agreement. The Commission's concern underlying this policy is that long-term customers should not need to choose between redirecting on a firm basis and maintaining rollover rights, rather their rollover rights should be retained consistent with the long-term nature of their service.

1281. In *Commonwealth Edison Co.*, the Commission explained that a ''request to change a delivery point on a firm basis for one month and then to revert to its original delivery point does not convert its existing long-term firm transmission service agreement into two separate short-term transmission service agreements.'' [782] The Commission stated that section 22.2 was intended to provide flexibility to transmission customers to permit them to react in a competitive market and that some amount of this flexibility would be lost if a long-term firm transmission customer seeking to modify its delivery points would lose its rollover rights.[783]

1282. The Commission affirmed this policy in *American Electric Power Service Corp.*[784] In that case, a long-term transmission customer (Exelon) had been granted a short-term redirect, but denied rollover rights on the redirected path. The Commission found the denial of rollover rights was improper, since the ''redirect request made by Exelon did not convert Exelon's long-term firm transmission service to short-term service, and, therefore, did not affect Exelon's rollover rights under its long-term firm transmission service agreement.'' [785] Thus, there is no inconsistency between the Commission's redirect policy and Order No. 676.

[778] *E.g.*, EEI, NorthWestern, and Seattle.

[779] *See Standards for Business Practices of Interstate Natural Gas Pipelines,* Order No. 587–N, FERC Stats. & Regs. ¶ 31,125 at P 23 (2002).

[780] *See* Order No. 676 at P 12.

[781] TranServ explains that these are two primary features in a revised WEQ 001–9.7 standard that was open for public comment.

[782] 95 FERC ¶ 61,027 at 61,083 (2001).

[783] The Commission, however, recognized that this flexibility was not unlimited—any change to a delivery point is treated as a new request for service for purposes of the availability of capacity.

[784] 97 FERC ¶ 61,207 at 61,905–06 (2001).

[785] *Id.*

c. Redirects as New Requests for Service

Comments

1283. With respect to the provision in section 22.2 of the *pro forma* OATT specifying that requests to redirect on a firm basis be considered new requests for service, LPPC and NPPD ask that this provision be modified to ensure that a customer redirecting its service will retain a higher priority for service in the transmission provider's queue than new customers. LPPC argues that it is inequitable to require customers to compete for capacity as though their loads were incremental to the system when they are simply changing their receipt points as a matter of necessity (since suppliers may commence serving other loads or cease doing business). EEI argues on reply that, if LPPC's proposal would give customers priority at new points of receipt and delivery regardless of whether the redirected service creates system impacts different from the old service, the proposal would replace ''first-come, first-served'' priority with a system in which customers would never know for sure whether their own requests for service would be displaced by subsequent requests for redirected service. EEI cautions that the transmission system simply cannot be planned and constructed with enough spare capacity to allow any customer to redirect service to any point that it chooses at any time.

1284. Bonneville similarly argues that a redirect request should meet the same term and notice requirements as a new request given that the transmission provider's planning horizon and the amount of time needed to remarket unused capacity is no different for a redirect and a new transmission service request. APPA argues on reply that it is unclear how Bonneville's request would affect load-serving transmission customers that cannot obtain power supply agreements of a term sufficient to dovetail with the term requirements for a new request. Imperial recommends that redirects be evaluated using ATC at the time of the redirect request, like any other new request for service, but that the transmission provider be given additional time to determine whether native load growth will prevent rollover rights for the redirects.

Commission Determination

1285. Section 22.2 of the *pro forma* OATT provides that redirects ''shall be treated as a new request for service in accordance with section 17,'' except that the transmission customer may not be required to pay an additional deposit in certain circumstances. Therefore, a redirect right does not grant the customer access to system capacity or queue position different from other customers submitting new requests for service. A redirect request must be evaluated in accordance with section 17 using the same system assumptions and analysis applicable to any other new request for service, including whether sufficient ATC exists to accommodate the request. The Commission concludes it would be inappropriate, and contrary to the *pro forma* OATT, to grant redirects special queue treatment.

1286. Regarding Imperial's request that transmission providers be given additional time to determine whether native load growth will prevent rollover rights for the redirects, we find that redirects should be studied like any other new request for firm point-to-point service. Transmission providers must examine whether any request, a firm redirect request or a new service request, would be affected by future native load growth resulting in possible rollover rights restrictions, so we see no need to provide additional time for transmission provider analysis of firm redirect request.

d. Pricing for Redirects

Comments

1287. TranServ requests that the Commission resolve a disagreement among WEQ participants regarding the pricing of redirects as requests for new service. TranServ asks whether the failure to charge an incremental uplift between the original and redirected rate (*e.g.*, respectively, the monthly rate and daily on-peak rate) would constitute the offering of a discount for daily service that in turn must be posted for all other paths to the same point of delivery. TranServ argues that it is reasonable to charge an incremental uplift such that the rate paid by the redirect customer would be on par with that paid by any other transmission customer reserving (daily) short-term firm service of like duration (*i.e.*, a ''new request for service''), and the customer would pay the difference between the daily on-peak rate and 1/30th of the monthly rate.

1288. Southern argues that, with respect to the price for redirects, if redirected hourly firm service is more valuable than firm service, economic theory would dictate that customers should be required to pay for that added value.

Commission Determination

1289. The Commission has not established a single, industry-wide pricing policy for redirects and did not propose a pricing policy in the NOPR. As a result, a uniform pricing method for redirects is beyond the scope of this proceeding. Nevertheless, we note that the Commission explained in a recent order that its policy does not allow transmission providers to collect additional charges when a firm point-to-point customer redirects on a non-firm basis.[786] The Commission concluded that it would not subject non-firm redirects to the *Appalachian* Method of pricing,[787] which is premised on the assumption that a customer using the transmission system for the 16 peak hours of the day should pay the same contribution to fixed costs as a customer who has reserved capacity on a daily basis. This is because the redirecting customer already would have paid for firm service over all on-peak and off-peak hours during the reservation period of its service, therefore, there is no need to ensure that the customer pays a premium for the opportunity to cherry pick the best hours each day. Furthermore, because the Commission is not requiring the provision of hourly firm service, Southern's argument regarding redirected hourly firm service is now moot.

e. Other Issues

Comments

1290. EEI agrees with the Commission's proposal to clarify that network customers may not redirect network transmission service. Alberta Intervenors contend that undue discrimination remains because the flexibility to modify points of receipt and delivery that the network customer enjoys through ''parking'' and ''hubbing'' is not likewise granted to a point-to-point customer. Alberta Intervenors recommends that the *pro forma* OATT either make a common service available to all participants (not just network customers) or prohibit network customers from using point-to-point services for parking and hubbing.

1291. Imperial asks the Commission to clarify that a transmission customer should not be able to make multiple redirects. Imperial explains that this clarification would address two concerns: multiple short-term changes raise reliability concerns and often there is insufficient time for the released capacity to be used by another customer; and the burden on properly scheduling for reliability increases exponentially when there are redirects of redirects.

[786] *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,095 at P 79–85(2007).

[787] *See Appalachian Power Co.*, 39 FERC ¶ 61,296 (1987).

1292. MISO/PJM States argue that because RTOs are not likely to engage in discrimination with respect to redirects, the Commission should not modify RTO redirect policies in the instant rulemaking proceeding.

Commission Determination

1293. The Commission adopts the NOPR proposal and finds that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. Unlike point-to-point service, network service involves no identified contract path and thus is not a directable service. A network customer seeking to substitute one resource for another already has the ability under the *pro forma* OATT to terminate its existing designation and designate a new resource on an as-available basis. If necessary, the network customer may then request to redesignate its original network resource by making a request to designate a new network resource. Alternatively, the network customer could use secondary network service if it wants to substitute a non-designated network resource for a designated network resource on an as-available basis.

1294. For similar reasons, the Commission denies Alberta Intervenors' request. The Commission has explained that customers must choose between point-to-point and network services, each of which has its own advantages and risks.[788] The Commission declined to implement a single form of transmission service in Order No. 888, concluding that point-to-point and network services are the appropriate base-line services under the *pro forma* OATT, and Alberta Intervenors offer no justification for departing from that approach now. Alberta Intervenors parking and hubbing related arguments alleging that network service is commonly used to purchase power intended for sales to third parties is addressed in section V.D.7 of this Final Rule. Although we deny Alberta Intervenors' request, we expect that the reforms adopted in this Final Rule will provide point-to-point customers with increased service options and flexibility.

1295. Implementing Imperial's proposal would prevent customers from redirecting for a short period or periods of time and then redirecting back to their original points, making redirects a less valuable option for customers. Multiple redirects are allowed only if the customer can meet the scheduling and other requirements for new requests for service under the *pro forma* OATT. As long as the customer meets these requirements, the Commission believes that the ability to redirect service does not present an unreasonable burden to transmission providers. As for applicability to RTOs and ISOs, we explain our compliance requirements in section IV.C of this Final Rule. To the extent an RTO's or ISO's redirect policy does not conform to the *pro forma* OATT, as amended by this Final Rule, the RTO or ISO must demonstrate that its policy is consistent with or superior to the *pro forma* provisions in accordance with the compliance procedures set forth in that section.

5. Acquisition of Transmission Service

a. Processing of Service Requests

1296. The *pro forma* OATT includes requirements that transmission providers process requests for transmission service in a timely fashion. Section 17.5 (Response to a Completed Application) and section 18.4 (Determination of Available Transmission Capability) of the *pro forma* OATT provide that following the receipt of a completed application for service, the transmission provider must respond to transmission customer requests for determinations of the availability of firm and non-firm transmission capacity on a timely basis. The transmission provider must make the determination as soon as reasonably practicable after receipt but no later than certain specified time periods (or such time periods generally accepted in the region).

1297. Section 19 (Additional Study Procedures for Firm Point-to-Point Transmission Service Requests) of the *pro forma* OATT provides deadlines that transmission providers must adhere to in issuing system impact study agreements and facilities studies agreements and that transmission customers must abide by in responding to these study agreements. Section 19 requires transmission providers to use due diligence to complete system impact studies and facilities studies within 60 days. Section 32 of the *pro forma* OATT (Additional Study Procedures for Network Integration Transmission Service Requests) contains similar due diligence deadlines for completing system impact studies and facilities studies associated with requests for network service.

(1) Posting Performance Metrics

NOPR Proposal

1298. In the NOPR, the Commission proposed to require transmission providers to post on their OASIS sites metrics that track their performance in processing system impact studies and facilities studies associated with requests for transmission service. The Commission proposed that transmission providers calculate the proposed performance metrics separately for affiliates and non-affiliates and for requests for short-term and long-term transmission service.

1299. In addition, the Commission proposed to require a notification filing and the posting of additional metrics if a transmission provider completes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadline in the *pro forma* OATT for two consecutive quarters. Starting the quarter after a notification filing, the transmission provider would be required to post the following information on OASIS: (1) The average, across completed system impact studies, of the employee-hours expended per completed system impact study, (2) the average, across completed facilities studies, of employee-hours expended per completed facilities study, (3) the number of employees devoted to processing system impact studies, and (4) the number of employees devoted to processing facilities studies. The Commission proposed that transmission providers post these additional performance metrics until they process at least 90 percent of all system impact and facilities studies within 60 days after the study agreement has been executed. The additional performance metrics also would be calculated separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service.

Comments

Standard Performance Metrics

1300. Transmission customers and a number of other commenters generally support or do not oppose the Commission's proposal to require transmission providers to post performance metrics.[789]

1301. Southern and Salt River oppose the proposal, arguing that most of the data needed to compute the metrics is already available on OASIS. Southern asserts that the NOPR does not explain why the currently available information is inadequate or how the proposed metrics would not be duplicative and, thus, does not fully justify the need for reform. Southern also argues that the Commission's proposal will impose

[788] Order No. 888–A at 30,260.

[789] *E.g.*, ELCON, Suez Energy NA, Powerex, Seattle, TAPS, Constellation, Entegra, NRECA, TDU Systems, Regional Electricity Committee, MISO, MidAmerican, FirstEnergy, Tacoma, EEI, Nevada Companies, and TranServ.

costs and burdens on transmission providers, and ultimately those who use their services, that do not correspond with the limited benefits that might be gained. Salt River believes that performance tracking requirements should be established on a case-by-case basis in response to complaints. NorthWestern believes the 60 days should be a target, but not a deadline, and, as such, transmission providers should not be required to report performance metrics that summarize the time they take to perform the studies.

1302. Several commenters requested clarification on certain features of the Commission's proposal. Nevada Companies asks the Commission to be very specific as to what statistical data items are to be reported on the OASIS so that transmission providers do not inadvertently violate the confidentiality of their transmission customers. PNM-TNMP requests clarification that the standards set out in the NOPR are solely applicable to processing of transmission delivery service requests, and not to interconnection service requests. Insofar as the Commission determines that performance metrics should be posted, Southern asks the Commission to clarify that the proposed posting of performance metrics also would be required of RTOs and ISOs.

1303. A number of commenters suggest that the Commission modify the performance metrics that transmission providers are required to post. EEI suggests that NAESB develop the metrics that transmission providers are required to post, using the metrics contained in the NOPR as guidance. EEI and MidAmerican suggest that the performance metrics include information about the degree to which transmission customers delay the study process. MISO suggests that transmission providers post metrics related to the time transmission customers take to respond to the results of completed system impact studies and facilities studies. Southern asserts that fewer metrics should be required and that they should relate directly to the study-timing concerns raised in the NOPR. Bonneville and MISO argue that transmission providers should not have to post information about the cost of transmission system upgrades recommended in the request studies. Bonneville believes that the average cost of recommended upgrades is misleading because it will mask the wide variation in such costs. MISO suggests that transmission providers also report the standard deviation for study completion times. Southern asserts further that the OATT does not specifically provide for a system impact study or facilities study to be performed on a short-term basis, so any metrics required as part of OATT reform should not include short-term requests. CREPC suggests that performance metrics be calculated separately for renewable resources.

1304. Several commenters suggest that transmission providers post additional information to further enhance transparency. A number of commenters suggest that the Commission require the posting of the disposition of all transmission service requests, including those not requiring studies.[790] TDU Systems suggest that the Commission require transmission providers to post the parameters of each denied request. MISO suggests that transmission providers provide a narrative to explain any anomalous study costs that may affect the posted average cost. If a transmission provider anticipates that it will miss the study deadline date, NRECA suggests that it should post that information, the expected finish date, and a reason for not being able to meet the deadline.

1305. EEI recommends that the Commission delegate to NAESB the responsibility for developing the Standard and Communications Protocols, business practices and OASIS modifications that will be necessary to provide the metrics.

Additional Performance Metrics (After Two Quarters of Late Studies)

1306. EEI and Southern oppose the Commission's proposal to require transmission providers that fail to complete studies in a timely manner to post additional performance metrics that measure the labor input used to complete studies. EEI asserts that there is little value to be gained from posting the additional information that the Commission proposes. EEI believes the information concerning the number of employees who perform studies will not be determinative of responsibility for the delay because the significant issue is whether the number of studies that the transmission provider is required to perform or the total amount of time needed to perform studies has increased significantly or whether customers caused the delays. Southern questions the Commission's legal authority to require transmission providers that do not complete studies in a timely manner to post additional performance metrics, citing *Cal. Ind. Sys. Operator Corp.* v. *FERC*.[791] Southern characterizes the Commission's proposal as a punishment for delays in processing request studies.

1307. Several other commenters suggest changes to the Commission's proposal. Southern believes the submission of a notification of extenuating circumstances should suspend the obligation to post the additional metrics proposed in the NOPR. EEI and Southern argue that the Commission should be certain that it is collecting such information only from those transmission providers that, for no other reason except themselves, fail to consistently evaluate studies within the 60-day due diligence period. Therefore, if a transmission provider demonstrates that delays in completing studies are due to extenuating circumstances, then EEI and Southern believe the Commission should not require the transmission provider to post the additional metrics. MISO believes the Commission should exempt RTOs from the additional employee performance metrics proposed in the NOPR for the same reason that the Commission proposed to exempt RTOs from operational penalties for untimely completion of studies, as MISO claims the additional posting requirements are in the nature of penalty. Bonneville believes the proposed metrics will be misleading whenever a transmission provider employs outside consultants to perform or assist with studies. Therefore, Bonneville suggests that the Commission add two other metrics, the number of studies performed entirely by consultants and, in the case of studies performed by a combination of employees and consultants, the average percentage of the study performed by consultants.

Commission Determination

Standard Performance Metrics

1308. The Commission will require transmission providers to post the performance metrics proposed in the NOPR, as modified by this Final Rule. The proposed metrics will enhance the transparency of the study process and shed light on whether transmission providers are processing request studies in a non-discriminatory manner. We also agree with comments by MidAmerican and EEI that transmission providers should be able to track delays in the study process caused by transmission customers. Doing so will allow the Commission and market participants to determine the extent to which delays by transmission customers are causing transmission providers to process request studies on an untimely basis, which will add needed transparency to the study process.

[790] *E.g.*, CREPC, MISO, Constellation, and TDU Systems.

[791] 372 F.3d 395, 404 (D.C. Cir. 2004).

Therefore, we will revise the performance metrics transmission providers are required to post to include metrics that track delays by transmission customers.

1309. Transmission providers will be required to post the performance metrics, outlined below, for each calendar quarter. Transmission providers will be required to begin tracking their performance upon the effective date of this Final Rule and keep the quarterly performance metrics posted on their OASIS sites for three calendar years. The transmission provider will be required to post the quarterly performance metrics within 15 days of the end of the quarter. The performance metrics outlined below must be calculated separately for affiliates' and non-affiliates' requests, in order to identify potential instances when the transmission provider is processing requests on a discriminatory basis. The transmission provider is required to aggregate studies associated with requests for short-term and long-term transmission service when calculating the metrics defined below. While a transmission provider could offer to study a request for short-term firm point-to-point transmission service, we acknowledge that the transmission customer often is unwilling to pay for such a study. Therefore, to ease the reporting burden, the transmission provider is not required to report the performance metrics defined below separately for requests for short-term and long-term firm point-to-point transmission service. A transmission provider is also required to post performance metrics for studies that it conducts for RTOs.

1310. A transmission provider is required to post the following set of performance metrics on a quarterly basis:

- Process time from initial service request to offer of system impact study agreement pursuant to sections 17.5, 19.1 and 32.1 of the *pro forma* OATT
  - Number of new system impact study agreements delivered to transmission customers
  - Number of new system impact study agreements delivered to the transmission customer more than 30 days after the transmission customer submitted its request
  - Average time (days) from request submittal to change in request status
  - Average time (days) from request submittal to delivery of system impact study agreement
  - Number of new system impact study agreements executed
- System impact study processing time pursuant to sections 19.3 and 32.3 of the *pro forma* OATT
  - Number of system impact studies completed
  - Number of system impact studies completed more than 60 days after receipt of executed system impact study agreement
  - Average time (days) from receipt of executed system impact study agreement to date when completed system impact study made available to the transmission customer
  - Average cost of system impact studies completed during the period
- Service requests withdrawn from system impact study queue
  - Number of requests withdrawn from the system impact study queue
  - Number of system impact studies withdrawn more than 60 days after receipt of executed system impact study agreement
  - Average time (days) from receipt of executed system impact study agreement to date when request was withdrawn from the system impact study queue
- For all system impact studies completed more than 60 days after receipt of executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data)
- Process time from completed system impact study to offer of facilities study pursuant to sections 19.4 and 32.4 of the *pro forma* OATT
  - Number of new facilities study agreements delivered to transmission customers
  - Number of new facilities study agreements delivered to transmission customers more than 30 days after the completion of the system impact study
  - Average time (days) from completion of system impact study to delivery of facilities study agreement
  - Number of new facilities study agreements executed
- Facilities study processing time pursuant to sections 19.4 and 32.4
  - Number of facilities studies completed
  - Number of facilities studies completed more than 60 days after receipt of executed facilities study agreement
  - Average time (days) from receipt of executed facilities study agreement to date when completed facilities study made available to the transmission customer
  - Average cost of facilities studies completed during the period
  - Average cost of recommended upgrades for facilities studies completed during the period
- Service requests withdrawn from facilities study queue
  - Number of requests withdrawn from the facilities study queue
  - Number of facilities studies withdrawn more than 60 days after receipt of executed facilities study agreement
  - Average time (days) from receipt of executed facilities study agreement to date when request was withdrawn from the facilities study queue
- For all facilities studies completed more than 60 days after receipt of executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data).

1311. In response to Nevada Companies request that we clarify the statistical data items that are to be reported on OASIS pursuant to the Commission's proposal, we reiterate that transmission providers are required to provide summary data as defined above. We do not believe these data will violate the confidentiality of any transmission customer, even in the event the transmission provider has worked on a limited number of studies. We clarify that the performance metrics posting requirement discussed above is solely applicable to processing of transmission delivery service requests, and not to interconnection service requests. Finally, we clarify that RTOs and ISOs also are required to post the performance metrics described above. As we discuss below, we believe all transmission providers should be subject to the same reporting requirements.

1312. We disagree with Southern and Salt River which argue that the data already on OASIS is sufficient to accomplish our goal to enhance transparency of the transmission provider's request study processing. First, the data available on the OASIS template *transstatusaudit* does not contain the information necessary to calculate all of the performance metrics proposed in the NOPR.[792] For instance,

[792] The OASIS template *transstatusaudit* is defined in the Standards and Communications Protocols section of NAESB's WEQ Business Practice Standards. The template *transstatusaudit* is the audit component to OASIS template *transstatus* and, as such, contains information regarding the

Continued

transstatusaudit allows one to determine when a request was moved from ''received'' to ''study'' and then to ''accepted'' or ''counteroffer''. Depending on when the transmission provider moves the request into ''study,'' this information does not allow one to determine either whether the transmission provider provided a system impact study agreement within 30 days or whether the transmission provider completed the system impact study within 60 days. In addition, the transmission provider is required to make the data in *transstatusaudit* available on OASIS for only 90 days and available by request for three years.[793] As a result, market participants would be required to calculate the performance metrics they desire on a quarterly basis if they want to use just the data posted on OASIS. Finally, downloading *transstatusaudit* data for specific OASIS requests that required a system impact study or feasibility study can be cumbersome due to the manual nature of the download process. The transmission provider has the data necessary to calculate the proposed performance metrics readily available. We believe it is more efficient for a single transmission provider to calculate the performance metrics for its system rather than have multiple interested parties calculate the performance statistics for each transmission provider of interest.

1313. We also disagree with Southern's assertion that the costs and burdens to transmission providers are not justified by the benefits that might be gained. We are concerned that, under the existing *pro forma* OATT, transmission providers do not have adequate incentives to conduct studies on a timely and nondiscriminatory basis. First, transmission providers have incentives to discriminate against third parties and in favor of their affiliates (*i.e.*, to delay the study requests of nonaffiliates, but act more quickly on those of its affiliates). Second, transmission providers also can lack incentives to provide sufficient staff resources to support increasing demands in the study process. Given that most of the costs associated with the study process are operational, transmission providers, at most, will recover those costs without profit (*i.e.*, a return) and, if the demands of the study process are increasing, fail to recover such cost increases if the transmission provider is between rate cases. We therefore believe that there are several reasons that greater transparency is required to provide the correct incentives to comply with the *pro forma* OATT provisions respecting studies.

1314. We also note that virtually all commenters agree with our proposal to require transmission providers to calculate the above performance metrics. This support stems, in part, from transmission customers' perception that transmission providers do not exert sufficient effort to complete requests in a timely manner.[794] Delays in processing study requests can cause customers to incur material financial damage. Moreover, the data needed to calculate the required performance statistics is readily available to the transmission provider and, therefore, the cost to the transmission provider will be small relative to the benefits of enhanced transparency and assurance that the transmission provider is processing request studies in a timely and non-discriminatory fashion.

1315. Based on our experience and the comments received in response to the NOI and NOPR, the Commission believes the steps we take here are necessary to increase transparency for the processing of service requests by all transmission providers. It would be inappropriate, as some commenters suggest, to wait for specific complaints about specific transmission providers before requiring the transmission provider to calculate the performance metrics defined above. We conclude that the reporting requirements adopted in this Final Rule must be applied to all transmission providers in order to enhance the transparency of the study process and ensure that transmission provider processes study requests in a timely and non-discriminatory fashion for all transmission customers. The fact that the 60-day timeframe in the *pro forma* OATT is a target and not a deadline does not change the fact that requiring all transmission providers to post the performance metrics defined above will enhance the transparency of the study process.

1316. We will not adopt any of the changes to the proposed performance metrics requested by commenters, other than adding metrics to track delays by customers as discussed above. The Commission is in a better position to determine the specific performance metrics that will achieve our policy goals and thus we will not request that NAESB develop the metrics to be posted.[795] We believe the set of performance metrics we have chosen strike the appropriate balance between requiring information that will enhance transparency and help ensure that the transmission provider is processing request studies in a timely and non-discriminatory fashion while limiting the burden the transmission provider faces. For instance, we believe the performance metrics that address the cost of system impact studies and facilities studies as well as the cost of any proposed transmission upgrades can be calculated with relatively little effort by the transmission provider and should provide meaningful benefits to transmission customers. The transmission provider readily knows the cost of studies it completes and the costs of proposed system upgrades and summaries of this information should enhance the transmission customer's ability to decide whether to submit a request for service that may result in a study offer.

1317. We do not believe the relative benefits and burdens justify requiring the transmission provider to post performance metrics beyond those adopted in this Final Rule. For instance, requiring the transmission provider to calculate additional summary information or post long narratives to explain anomalous upgrade costs do not appear necessary at this time to achieve our stated policy goals, particularly since transmission customers can request data associated with completed system impact studies and facilities studies pursuant to section 37.6(b)(2)(iii) of the Commission's regulations.[796] In addition, we do not believe transmission customers, beyond the transmission customer directly affected, would benefit from the information NRECA suggests the transmission provider should be required to post when it anticipates that it will not complete a study within the 60-day due diligence timeframe. Section 19.3 of the *pro forma* tariff already requires the transmission provider to notify the affected transmission customer when it will not be able to complete a study within the 60-day due diligence timeframe, provide an expected completion date, and explain why additional time is needed. We do

type of transmission service requested, affiliate status, date and time the transmission service was requested, and the date and time of all changes in request status (*e.g.*, place in study mode, confirmed or withdrawn).

[793] 18 CFR 37.7(b).

[794] *E.g.*, Constellation, EPSA NOI Comments, Arkansas Cities NOI Comments, APPA NOI Reply Comments, and Powerex NOI Reply Comments 795 As noted in P 1318, we direct public utilities working through NAESB to develop protocols for posting the performance metrics required here so they will be posted in a consistent fashion.

[795] As noted in P 1318, we direct public utilities working through NAESB to develop protocols for posting the performance metrics required here so they will be posted in a consistent fashion.

[796] 18 CFR 37.6(b)(2)(iii).

not believe other transmission customers would benefit enough from this information to justify requiring the transmission provider to post it. Similarly, we do not believe the benefit to market participants justifies the burden of requiring transmission providers to calculate performance metrics separately for renewable resources.

1318. We agree, however, with EEI's recommendation that the Commission delegate to NAESB the responsibility for developing the Standard and Communications Protocols, business practices and OASIS modifications that will be necessary to provide the performance metrics adopted above. NAESB is in the best position to develop the standards and the processes by which the performance metrics are posted.

Additional Performance Metrics (after two quarters of late studies)

1319. The Commission also adopts the NOPR proposal to require transmission providers to submit a notification filing with the Commission in the event the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters. This filing must be filed within 30 days of the end of the second quarter during which the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT. For the purposes of calculating this notification trigger, the transmission provider is required to aggregate all system impact studies and facilities studies that it completes during the quarter for non-affiliates.[797] The transmission provider may explain in its notification filing that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT.

1320. As the Commission proposed in the NOPR, starting the quarter following a notification filing, the transmission provider will be required to post: (1) The average, across completed system impact studies, of the employee-hours expended per completed system impact study; (2) the average, across completed facilities studies, of employee-hours expended per completed facilities study; (3) the number of employees devoted to processing system impact studies; and (4) the number of employees devoted to processing facilities studies. The transmission provider is not required to post these additional performance metrics separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service. The transmission provider is instead required to aggregate studies associated with requests for short-term and long-term transmission service when calculating these additional metrics. The transmission provider is not required to post the additional metrics if the Commission concludes that delays in completing studies are due to extenuating circumstances. However, the transmission provider is required to post the additional metrics while the Commission considers the transmission provider's notification filing arguing that extenuating circumstances prevented it from processing request studies on a timely basis. Based on the timing described in this Final Rule, the transmission provider will be required to post the additional performance metrics approximately two months after the provider makes its notification filing. The Commission will have this time to evaluate the transmission provider's contention that it was unable to complete request studies due to extenuating circumstances. As a result, we expect the transmission provider with legitimate extenuating circumstances typically will not have to post any additional metrics.

1321. We disagree with those arguing that information concerning the number of employees who perform studies will not be determinative of responsibility for the delay. The transmission provider will have the right to establish that it is unable to perform studies in a timely manner because of factors outside its control. We received a number of comments to the NOPR and NOI that suggest that transmission customers believe transmission providers fail to complete studies on a timely basis because they do not have sufficient staff to perform the studies.[798] As explained above, this is one of the concerns that has led us to adopt these reforms. The additional metrics will serve to shed light on the transmission provider's resource commitment, enhance the transparency of the study process, and increase the transmission provider's incentive to staff its study function appropriately.

1322. The additional posting requirement is not a penalty or a punishment. We opted not to require the transmission provider to post these additional performance metrics on a regular basis out of a desire to limit the transmission provider's reporting burden. However, once the transmission provider has stopped completing studies on a timely basis, we believe the enhanced transparency justifies the additional reporting burden. As a result, ISOs and RTOs also will be required to post the additional performance metrics described above. We disagree with Southern's argument that we lack jurisdiction to require additional posting. The posting requirements are directly related to *pro forma* OATT obligations that are necessary to remedy undue discrimination and, hence, necessarily derive from our broad discretion in fashioning remedies to undue discrimination. We are not attempting to dictate a transmission provider's internal staffing decisions; rather, we illuminate the transmission provider's compliance with its *pro forma* OATT obligations to perform studies within certain deadlines and on a nondiscriminatory basis.

1323. We will not add the two other metrics suggested by Bonneville regarding the number of studies performed entirely by consultants and, in the case of studies performed by a combination of employees and consultants, the average percentage of the study performed by consultants. Rather, transmission providers should include the time spent by consultants on studies in the performance metrics defined above.

(2) Operational Penalties for Late Studies

NOPR Proposal

1324. The Commission proposed to impose operational penalties when transmission providers routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. Under the proposal, a transmission provider who processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the *pro forma* OATT for two consecutive quarters would be required to notify the Commission. In this notification filing, the transmission provider may explain that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the *pro forma* OATT. The transmission provider

[797] For instance, if the transmission provider completes 4 non-affiliates' system impact studies during the quarter with 2 completed more than 60 days after the system impact study agreement was executed and completes 2 non-affiliates' facilities studies during the quarter with none completed more than 60 days after the facilities study agreement was executed, then the transmission provider will be deemed to have completed 2 out of 6 (33 percent) studies outside of the deadlines in the *pro forma* OATT.

[798] *E.g.*, Constellation, EPSA NOI Comments, Arkansas Cities NOI Comments, APPA NOI Reply Comments, and Powerex NOI Reply Comments.

would be subject to an operational penalty if it continues to be out of compliance [799] with the deadlines prescribed in the *pro forma* OATT for each of the two quarters following its notification filing.

1325. The Commission proposed that the operational penalty be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. For any system impact study or facilities study completed during that quarter and more than 60 days after the study agreement was executed, the Commission proposed a penalty equal to $500 for each day the transmission provider takes to complete the study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the Commission proposed a penalty equal to $500 for each day the study has been in the study queue beyond 60 days.

1326. In addition to the proposed operational penalties, the Commission indicated that it would order other remedial actions, consistent with the Policy Statement on Enforcement, to be determined on a case-by-case basis. The Commission proposed that RTOs not be subject to this penalty regime because of the RTOs' independence.

Comments

1327. Transmission providers generally oppose the Commission's proposal.[800] Some opponents argue that, to the extent the Commission is going to impose penalties, it should do so on a case-by-case basis.[801] Opponents cite a number of reasons the Commission should not impose the proposed operational penalty regime. Several opponents caution that imposing a penalty may lead transmission providers to either prematurely deny a request or accept a request to the detriment of system reliability.[802] Several opponents argue that many transmission requests introduce unique complexities into the study process, so a firm 60-day deadline is not workable in practice.[803] Several opponents argue that the Commission's proposed penalty regime is inconsistent with the new requirements the Commission has proposed for regional planning and requirements to consider redispatch in the system impact study.[804] In its reply comments, EEI argues that due process requires that the Commission not impose penalties on transmission providers for study delays because, in EEI's view, it is highly likely that the delays will have been caused by factors or events that were beyond the transmission provider's control. Southern asserts that any scheme of operational penalties associated with the processing of studies cannot be implemented fairly unless and until the problem surrounding the submission of multiple requests is addressed. Southern argues that the Commission would violate a transmission provider's due process rights if it were to impose penalties for delays caused by transmission customers. CREPC proposes that transmission projects that cross seams not be subject to penalties, arguing that such an exception will create a level playing field for those transmission providers in the West working with the CAISO and foreign transmission owners to resolve transmission service requests.

1328. A number of commenters ask the Commission to clarify specific elements of the proposed operational penalty regime. Several commenters argue that the proposal does not clearly provide for an exemption from operational penalties if the failure to meet the timeliness criteria is a result of extenuating circumstances or customer caused delays, thereby denying transmission providers due process.[805] Several commenters ask the Commission to clarify that a transmission provider is not subject to operational penalties if the transmission provider's failure to meet the compliance threshold following its notification filing is due to extenuating circumstances.[806] Southern asks that the Commission clarify that the submission of a notification of extenuating circumstances would suspend the obligation of a transmission provider to process at least 90 percent of the study requests within the proposed deadlines, until such time as the Commission issues a final determination on the notification of extenuating circumstances. Tacoma asks the Commission to ensure that the processing time is measured from the point that the customer provides complete information.

1329. EEI recommends that the Commission hold a technical conference to determine the extent to which studies are not being completed within 60 days, the principal causes of delays in completing studies within 60 days and whether the increased planning and coordination requirements proposed by the Commission will result in additional time being needed to complete the studies. EEI believes the Commission is far more likely to arrive at a reasonable conclusion concerning these issues after a technical conference than if it simply imposes penalties for failures to complete all studies within 60 days. Seattle believes the proposed penalties should not be implemented until providers and customers have had at least one year of experience working with the performance metrics.

1330. Transmission customers generally support the Commission's proposal to impose operational penalties when a transmission provider routinely fails to meet the 60-day due diligence deadlines.[807] In its reply comments, Entegra argues that the question is not whether a transmission provider has sufficient margins of flexibility, but whether the transmission provider has any stake in meeting the deadlines. Occidental argues that transmission providers may have little incentive to meaningfully address customers' issues without the prospect of a prospective remedy. Responding to EEI's due process argument, TDU Systems in reply assert that imposition of penalties in this instance raises no more due process concerns than those operational penalties that transmission customers are routinely subjected to under the OATT. TDU Systems argue that, should the Commission determine that transmission providers are entitled to challenge any operational penalty for failure to process service requests in a timely manner, then those challenges must be on terms and conditions that are comparable to those available to transmission customers—a complaint pursuant to FPA section 206. TDU Systems believe that the proposed ''explanatory statement'' contemporaneous with any notification filing is a form of expedited review that is clearly not comparable to the treatment of customers under the tariff.

[799] The transmission provider would be deemed to be out of compliance if it completes 10 percent or more of non-affiliates' system impact studies and facilities studies outside of the deadlines prescribed in the *pro forma* OATT.

[800] *E.g.*, EEI, MidAmerican, Entergy, Southern, Imperial, NorthWestern, PNM–TNMP, Salt River, and Bonneville Reply.

[801] *E.g.*, EEI, Southern, and PNM–TNMP Reply.

[802] *E.g.*, MidAmerican, Southern, Imperial, and EEI Reply.

[803] *E.g.*, MidAmerican, Southern, NorthWestern, Northwest IOUs, and PNM–TNMP Reply.

[804] *E.g.*, MidAmerican, Southern, and EEI Reply.

[805] *E.g.*, EEI, Southern, Northwest IOUs, and MidAmerican.

[806] *E.g.*, EEI and MidAmerican.

[807] *E.g.*, Suez Energy NA, TAPS, Constellation, Entegra, TDU Systems, CREPC, and Nevada Companies.

1331. Several transmission customers question whether the proposed penalty level is sufficient to ensure compliance.[808] Constellation recommends a penalty of up to $10,000 per day per violation. Entegra suggests the Commission set the penalty equal to the higher of the lost opportunity cost to the customer resulting from the delay, if any, or $1,000 for each day. Entegra also suggests that penalties should be assessed automatically, without a notification filing to the Commission. In its reply comments, EEI argues that the total penalty for delayed studies will be far higher than $500 per day if the transmission provider is processing more than five requests per 60-day period, which EEI asserts is extremely likely.

1332. Constellation asks the Commission to consider whether to require the transmission provider to engage an independent transmission administrator to the extent a transmission provider's posted performance metrics are not accurate or the transmission provider persistently fails to adhere to the relevant timelines.

1333. Several commenters suggest that the Commission extend the study completion deadlines, such as to 120 or 180 days, at least for the purposes of assessing penalties.[809] Bonneville suggests that the Commission change the service request study process to match the interconnection study process as articulated in the Large Generator Interconnection Procedures. Imperial recommends that instead of mandating a nationwide study schedule, each of the NERC regions should establish a schedule taking into account the various needs of the region. Southern suggests restarting the 60-day due diligence period for any study that experiences a delay that cannot properly be attributed to the transmission provider. In contrast to the suggestions to increase the study time, Entegra suggests that the Commission consider changing the due diligence deadlines to 30 days to further the goal of encouraging timeliness in completing required studies.

1334. Several commenters suggest methods for distributing the operational penalties the transmission provider pays for late studies. TAPS believes that penalty revenues should go to victims of study delay. Similarly, Entegra believes the penalty should take the form of a credit against the transmission customer's obligation to reimburse the transmission provider for study costs, with any amount in excess of the study costs payable to the transmission customer, in recognition of the harm to transmission customers when required studies are not completed expeditiously. CREPC asks the Commission to clarify how it plans to determine which unaffiliated transmission customers will receive operational penalty payments. CREPC also asks the Commission whether the $500 per day penalty is a flat rate that would be pro-rated among eligible non-offending, unaffiliated transmission customers or if the $500 is a rate paid to each eligible transmission customer.

1335. Commenters affiliated with RTOs and one transmission customer support the Commission's proposal to exempt RTOs from penalties for late studies.[810] MISO asserts that RTOs do not have incentives to delay the processing of transmission service requests, as they have no affiliates to favor and because their Commission-approved design and internal procedures ensure their independence. MISO argues further that all transmission service requests benefit some RTO member and, as a result, RTOs have no disincentive to approve service so long as reliability is maintained. MISO/PJM States asserts that the NOPR proposal to exempt RTOs from operational penalties for late studies is appropriate because a penalty does not serve a useful purpose with respect to RTOs. TDU Systems state that an RTO should not be financially penalized for late studies because RTO independence should minimize incentives for affiliate preference and RTO members indirectly pay for all RTO incurred costs in any event.

1336. Most of those commenters not affiliated with an RTO oppose the proposal to exempt RTOs from penalties for late studies.[811] Southern argues that given that the Commission is seeking to increase transparency in the system, the Commission would undercut that goal by omitting a significant segment of the industry. TAPS argues that RTOs may still fail to complete studies on a timely basis due to competing internal priorities or bureaucratic indifference. Progress notes that the Commission has found that RTOs and ISOs should be subject to penalties for failure to meet reliability standards. Salt River argues that RTOs should be subject to operational penalties because the impact on the customer is identical if the request processing deadline is not met regardless of the type of provider conducting the study. Xcel notes that, historically, transmission owners need to complete facility studies in concert with RTOs, thereby giving the customer the most up-to-date and coordinated analysis. Consequently, Xcel believes it is imperative that both transmission owners and RTOs operate under the same rules, reporting obligations, and performance metrics in the OATT.

1337. In its reply comments, WPS disagrees with the Commission's proposal to exempt RTOs from penalties for their repeated failure to meet the 60-day due diligence requirements. WPS asserts that the Commission should impose penalties and prohibit the recovery of associated revenue where appropriate. WPS argues that RTO independence does not guarantee RTO competence or compliance in every instance. WPS believes imposing reporting obligations and penalties for failure to comply with tariff requirements, particularly tariff deadlines, will help to motivate compliance by ensuring that RTOs devote resources to tariff compliance. WPS acknowledges that a non-profit RTO has no dividends to cancel and likely no property to liquidate to cover these shortfalls, yet believes that such organizations can exercise cost-cutting measures, especially regarding rewards for employee performance, and thereby bear some financial responsibility and accountability for their operational violations. In the event of a penalty, WPS believes the Commission could require an RTO to take steps to cover its penalty-related revenue shortfall by cutting its budget, eliminating management bonuses and demonstrating that it has taken reasonable corrective steps before the Commission permits recovery of the remaining penalty revenue from its members and customers. To the extent some portion of an RTO's penalties are passed through to its market participants, including transmission owners, WPS argues that those market participants would be in a position to take actions similar to the actions taken by shareholders of a publicly traded company to motivate the RTO either by changing the RTO's processes or its Board of Directors.

1338. TAPS states that some adaptation of the penalties may be necessary to make them appropriate and effective in the non-profit RTO/ISO context, for example, by requiring a reduction in management compensation. TDU Systems recommend that RTOs be subject to the notification filing requirement that is part of the Commission's penalty

[808] *E.g.*, TAPS, Constellation, and Entegra.

[809] *E.g.*, Bonneville, MidAmerican, Progress Energy, NorthWestern, Northwest IOUs, and EEI Reply.

[810] *E.g.*, MISO, MISO/PJM States, TDU Systems, and Indianapolis Power Reply.

[811] *E.g.*, Southern, TAPS, Progress Energy, Salt River, and Xcel.

proposal, regardless of whether RTOs are subject to pay penalties. TDU Systems believe this reporting requirement would provide an objective measure of RTO efficiency. APPA believes steps should be taken to remedy tardy RTO processing of service requests, suggesting that performance incentives for RTO employees, if carefully designed, could be useful. In its reply comments, Duke argues that although transmission owners in RTOs should not pay the price for RTOs failures to abide by the tariff, RTOs lack of performance should be addressed by the Commission, perhaps in a separate proceeding.

1339. Transmission providers that have retained an independent tariff administrator suggest that these independent entities should also be exempt from operational penalties related to study completion times.[812] In their view, these independent entities also have no incentive to discriminate when completing service request studies. Similarly, NorthWestern argues that a transmission provider without an affiliate that could benefit from a delay in completing service request studies also should be exempt from paying the proposed operational penalties.

Commission Determination

1340. The Commission adopts the NOPR proposal to subject transmission providers to operational penalties when they routinely fail to meet the 60-day due diligence deadlines prescribed in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. Transmission providers must have a meaningful stake in meeting study time frames. As discussed above, a transmission provider will be required to make a notification filing with the Commission indicating that it has not completed request studies on a timely basis and may present evidence that extenuating circumstances prevented it from completing studies on a timely basis. The transmission provider then will be subject to an operational penalty if the transmission provider continues to be out of compliance with the deadlines prescribed in the *pro forma* OATT for each of the two quarters following its notification filing and the Commission determines that no extenuating circumstances exist to excuse the transmission provider's non-compliance. The transmission provider will be deemed to be out of compliance if it completes 10 percent or more of non-affiliates' system impact studies and facilities studies outside of the deadlines prescribed in the *pro forma* OATT. The operational penalty will be assessed on a quarterly basis, starting with the quarter following the notification filing and continuing until the transmission provider completes at least 90 percent of all studies within 60 days after the study agreement has been executed. For any system impact study or facilities study completed during that quarter and more than 60 days after the study agreement was executed, the penalty will equal $500 for each day the transmission provider takes to complete the study beyond 60 days. For any system impact study or facilities study that is still pending at the end of the quarter and that has been in the study queue for more than 60 days, the penalty will equal $500 for each day the study has been in the study queue beyond 60 days.

1341. The late study penalty regime described in this Final Rule will become effective at the same time as the rest of the new *pro forma* OATT. The penalty regime is designed so that the transmission provider has to be out of compliance for at least three quarters before it is subject to late study penalties. We believe nine months is sufficient time for the transmission provider to adjust its operations to the new requirements in this Final Rule, including penalties for late studies. That is, we believe transmission providers should be able to reallocate employees to study requests for service and hire new staff, to the extent these steps are necessary, by the time the transmission provider will be subject to civil penalties.

1342. The procedures underlying the operational penalty regime adopted in this Final Rule ensure that the due process rights of transmission providers are protected. In their notification filing, transmission providers will have the right to document and describe any unique complexities that particular requests introduce into the study process and that prevent the transmission provider from completing the study within a the 60-day due diligence time frame. Thus the 60-day time frame will continue to be a flexible deadline, especially given that the transmission provider is not required to complete all studies within 60 days. These due process rights provide a de facto case-by-case review of the transmission provider's efforts to complete studies on a timely basis.

1343. On review of a notification filing, we will waive operational penalties if a transmission provider establishes that its non-compliance is the result of factors or events that are truly beyond its control, including delays caused by the transmission customer. We will not, however, exempt all transmission projects that cross seams from operational penalties, as CREPC urges. We will consider the specific facts surrounding studies of such projects based on a transmission provider's notification filing. In response to TDU Systems, we acknowledge that the procedures for addressing a transmission provider's failure to conform to the 60-day time frame are not the same as the procedures applicable to a transmission customer that is assessed an operational penalty under the *pro forma* OATT. We believe such different procedures are justified in this instance. The other operational penalties in the *pro forma* OATT are assessed for failure to remain in compliance with strict requirements, while the study time frame is based on the transmission provider using its due diligence to complete studies within 60 days. The Commission recognizes that the transmission provider must have flexibility, within reason, to complete studies outside of this time frame. At the same time, the notification and penalty procedures we adopt in this Final Rule will ensure that this flexibility is not abused.

1344. We do not find the remaining comments in opposition to the operational penalty for late studies to be compelling, particularly given the flexibility built into our penalty regime. We would not expect a transmission provider to prematurely deny a request for service simply to avoid an operational penalty. According to section 17.5 of the *pro forma* OATT, a transmission provider must either grant service or offer the transmission customer a system impact study. The transmission provider does not have the option to simply deny the request for service. We therefore interpret comments that the transmission provider may prematurely deny a request to mean that the transmission provider will not explore all possible system upgrades or redispatch options as required by section 19.3 of the *pro forma* OATT or any conditional firm options discussed in section V.D.1. Such behavior would be a tariff violation that should be brought to our attention. The transmission provider is required under the *pro forma* OATT to provide a complete study and corresponding work papers to the transmission customer. If a transmission customer feels a system impact study is incomplete, it has recourse to call the Commission's Enforcement Hotline or file a formal complaint with the Commission.

1345. We also do not expect a transmission provider to accept a

[812] *E.g.*, Duke, MidAmerican, and TranServ.

transmission service request to the detriment of system reliability simply to meet the study time frame. First, the transmission provider is not required to complete every request study within 60 days. Second, to the extent our new requirements that the transmission provider consider conditional firm options and participate in regional planning cause study delays, the transmission provider can document and describe such delays in its notification filing. Finally, the transmission provider has been required to consider redispatch in the system impact study since Order No. 888 was issued, so the 60-day due diligence time frame should continue to be consistent with the long standing requirement to consider redispatch in the system impact study.

1346. As we discuss below, we believe NAESB's queue hoarding and queue flooding business practices, as well as additional reforms adopted in this Final Rule, will address the problem surrounding the submission of multiple requests. With regard to requests for a technical conference or further procedures to consider the effect of our operational penalty regime, we believe the commenters' proposals would largely provide anecdotal information and speculation on the impacts of the new planning and coordination requirements. Our experience from the last ten years, and the comments provided in response to the NOI and NOPR, provide a sufficient basis to develop a penalty regime. In addition, the very requirement that transmission customers post performance metrics and submit notification filings prior to assessment of operational penalties will provide actual experience with the new regime. As explained above, the notification procedures adopted today will ensure that we will not assess a penalty for late studies unless justified by the circumstances. We can propose additional changes to the study process or penalty regime based on the actual experience under this Final Rule if our experience warrants it.

1347. As described above, we adopt the proposal to set the operational penalty for late studies equal to $500 per day per late study. We believe $500 per day per late study is in line with the cost the transmission provider would incur to focus additional resources on processing requests studies. In addition, the penalty for being one month late, $15,000, is in line with the overall cost of the study. We conclude that the $500 per day per late study penalty is high enough to provide the incentive to transmission providers to comply with study processing deadlines in the *pro forma* OATT, while not being unnecessarily punitive. We believe that a penalty in the range of $10,000 per day per late study would be unnecessarily punitive. The proposal to set the penalty equal to the higher of the lost opportunity cost to the customer resulting from the delay, if any, or $1,000 for each day is administratively cumbersome and could result in administrative costs that are not justified. Finally, we believe the due process afforded the transmission provider is an important element of the penalty regime, so we decline to impose penalties automatically, without a notification filing to the Commission.

1348. As indicated in the NOPR, we may order other remedial actions in addition to the operational penalties described above, consistent with the Policy Statement on Enforcement. We will determine any other remedial action on a case-by-case basis. The decision to order other remedial actions will be based, among other things, on whether we believe the transmission provider is using the same due diligence to complete studies for non-affiliated customers as it uses to complete studies for itself. We do not believe it would be appropriate, as a general matter, to require a transmission provider to engage an independent transmission administrator to the extent its posted performance metrics are not accurate. As a threshold matter, Commission audit staff may audit the accuracy of a transmission provider's posted metrics. If we are concerned about the accuracy of a transmission provider's metrics, we will evaluate the use of third-party audits at that time. We will not prejudge which remedial actions we will consider if a transmission provider persistently fails to adhere to the relevant timelines. Rather, we will review each such instance on a case-by-case basis and determine the appropriate remedial action consistent with the Commission's Policy Statement on Enforcement.

1349. We clarify that a transmission provider is not subject to operational penalties if it can make a showing that its failure to meet the compliance threshold following its notification filing is due to extenuating circumstances, as we agree that the transmission provider should not be penalized for factors out of its control. The submission of a notification of extenuating circumstances will not, however, suspend the obligation of a transmission provider to process at least 90 percent of the study requests within the proposed deadlines, until such time as the Commission issues a final determination on the notification of extenuating circumstances. At the same time, we will not require the transmission provider to distribute its operational penalty while we are still considering the transmission provider's notification filing. The transmission provider nonetheless remains liable for paying the operational penalty for all request studies completed or outstanding after the notification filing and not completed within 60 days. This timing will balance the transmission provider's due process rights with the need to provide an incentive to the transmission provider to complete studies on a timely basis.

1350. We clarify that the processing time is measured from the point that the customer returns its executed study agreement to the transmission provider. By the time the transmission provider offers a system impact study agreement, it should have all the information it needs to complete the study. Pursuant to section 17.4 of the *pro forma* OATT, the transmission provider can deem a transmission service request deficient if the transmission customer does not provide all information the transmission provider needs to evaluate the request for service. We expect the transmission provider to use informal means to communicate the information it needs from the transmission customer before it deems a transmission service request deficient.

1351. We adopt the NOPR proposal to have the transmission provider distribute the operational penalty for late studies to all non-affiliated transmission customers, as discussed in section V.C.5.b of this Final Rule. We believe that a transmission provider that is not processing studies on a timely basis potentially harms all transmission customers, not just those with requests in the study queue. For instance, a transmission customer may decide against requesting service that it believes will require a system impact study if the transmission provider is not processing transmission service requests on a timely basis. Therefore, we will not adopt suggestions to distribute penalty revenue only to transmission customers that have request studies that are not completed within 60 days. We clarify that the penalty is $500 per day per late study, with the resulting total penalty revenue distributed to unaffiliated transmission customers as discussed in section V.C.5.b of this Final Rule. We clarify that the transmission provider will propose a method to determine how unaffiliated transmission customers will receive operational penalty payments, as discussed in section V.C.5.b of this Final Rule.

1352. We will not alter the 60-day study completion timeframe currently embodied in sections 19.3, 19.4, 32.3 and 32.4 of the *pro forma* OATT. We continue to believe, absent concrete evidence to the contrary, that the existing timeframe adequately balances the need for expeditious resolution of request studies and the need to ensure that the transmission provider can reliably accommodate the transmission service reserved. Moreover, we believe the penalty regime defined in this Final Rule protects the transmission provider in the event studies take longer to complete due to the new planning requirements defined in section V.B of this Final Rule or the new requirement to consider conditional firm options as defined in section V.D.1 of this Final Rule. We will not adopt the suggestion to restart the 60-day due diligence period for any study that experiences a delay that can not properly be attributed to the transmission provider. We reiterate that the transmission provider is not subject to penalties for late studies if it can establish that delays are due to factors the transmission provider cannot control.

1353. The Commission declines to adopt the NOPR proposal to exempt RTOs from operational penalties for completing studies on an untimely basis. We agree with those commenters that argue that RTO independence does not guarantee RTO competence or compliance in every instance and that RTOs may fail to complete studies on a timely basis due to competing internal priorities or staffing issues. Imposing penalties for failure to comply with the due diligence timeframe for completing studies will provide RTOs an appropriate incentive to comply with the *pro forma* OATT requirements and ensure that they devote adequate resources to tariff compliance. Finally, we note that subjecting RTOs to operational penalties for late studies is consistent with the Commission's decision to subject RTOs and ISOs to penalties for failure to meet reliability standards.[813] We believe that all transmission providers, including RTOs, should operate under the same rules, reporting obligations, and performance metrics in the OATT. We will nonetheless keep in mind the nature of an RTO's operations and the RTO's unique characteristics when we consider whether penalties would be appropriate. We agree that RTOs do not have an incentive to discriminate (which is one of the bases for this policy) and we agree that imposing a penalty raises the issue of cost recovery, as most RTOs are not-for-profit entities. We will therefore consider these and all other relevant factors in exercising our discretion whether to impose a penalty in a given circumstance.

1354. Consistent with the treatment of RTOs, we will not exempt independent entities that provide tariff administration from penalties for late completion of studies. As with RTOs, independence does not guarantee competence or compliance in every instance. Independent entities have a similar incentive to limit the personnel committed to processing request studies in an effort to reduce overhead costs. We believe that all entities administering the tariff should operate under the same rules, reporting obligations, and performance metrics in the *pro forma* OATT.

(3) Recovery Through Rates

NOPR Proposal

1355. The Commission proposed that a transmission provider cannot recover for ratemaking purposes any operational penalty it pays for failing to process transmission service studies on a timely basis.

Comments

1356. CREPC noted that, while it may be reasonable for an investor-owned utility to pay penalties without being allowed to recover the penalties in rates, this approach will be problematic for utilities that do not have shareholders.

Commission Determination

1357. We will prohibit all jurisdictional transmission providers from recovering penalties for late studies from transmission customers. We believe that all entities administering the tariff should operate under the same rules, reporting obligations, and performance metrics in the *pro forma* OATT. Non-profit transmission providers have other sources of money to pay penalties beyond the revenue they collect for sales of transmission service. Therefore, we require non-profit transmission providers to pay operational penalties for late studies from their other sources of money. This notwithstanding, we may consider factors such as an entity's financial ability to absorb a penalty in determining whether to impose penalties in the first instance.

(4) Fee for Multiple Self-Competing Transactions

NOPR Proposal

1358. In the NOPR, the Commission sought comment on a fee structure that could provide a disincentive for transmission customers to submit duplicative requests without penalizing transmission customers that have legitimate requests for transmission service. The Commission asked for detailed recommendations, including any proposed tariff language, regarding the standards it should use to identify requests that would be subject to a fee. The Commission also sought recommendations on the level of a fee that balances its policy goals to discourage requests for transmission service that the transmission customer does not intend to confirm while not discouraging legitimate requests for transmission service. Finally, the Commission sought comment regarding the circumstances, if any, under which the processing fee would be refunded to or credited to the transmission customer.

Comments

1359. A number of commenters express support for a fee for duplicative requests.[814] CREPC believes that queue blocking behavior should be discouraged so that legitimate requests lower in the queue are not disadvantaged. MISO believes the transmission provider should be allowed to charge a fee that is small enough to not create a barrier to entry yet high enough to ''add up'' for anyone wishing to flood the queue. MISO and Seattle suggest that the fee be based on the transmission provider's cost to review a request and handle the initial processing. MISO also believes the transmission provider should be able to charge a fixed dollar amount for any accepted requests that the customer wants to retract. Southern suggests that the Commission consider a procedure whereby transmission customers place a deposit with transmission providers to cover a certain number of requests that is forfeited once the requests reach a certain threshold and are deemed self-competing. TranServ suggests that the fee apply to requests for long-term firm transmission service and be based on duration of the request and not capacity requested as an incentive to the transmission customer to submit fewer combined requests where possible. TranServ suggests this fee could be

[813] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 at P 56 (2006) (''It is not arbitrary and capricious to treat all operators alike, including RTOs and ISOs, in terms of their liability for violation of a Reliability Standard.'').

[814] *E.g.*, MidAmerican, MISO, Seattle, Southern, TranServ, TAPS, and CREPC.

waived if the service request is submitted pre-confirmed.

1360. Most of the transmission customers and some transmission providers oppose the creation of a fee structure for duplicative requests for transmission service.[815] Several commenters argue that the Commission should determine whether the newly-adopted NAESB business practices and other reforms proposed in the NOPR can reduce the number of requests that the transmission customer does not intend to confirm.[816] Nevada Companies and Great Northern assert that the current deposit requirement serves to discourage multiple self-competing requests. Constellation asserts that the Commission should focus on narrowly-tailored penalties to deter market participants from intentionally jamming the queue.

1361. Several commenters suggest that a transmission provider that makes a showing that it is experiencing a significant problem with respect to customers' submission of multiple competing requests should be allowed to propose a fee to combat the problem.[817] MISO notes that the Commission has rejected a fee for unconfirmed requests in the past.[818]

1362. TAPS believes the fee revenue should be shared with network customers on a load-ratio share basis. TAPS also suggests that the fee apply to the transmission provider's merchant arm in a meaningful way.

1363. CREPC urges the Commission to adopt a simple, straightforward standard for determining duplicative requests, such as the same points of receipt and delivery, same source and sink, same time frame, and same firmness, as well as the same project at multiple locations. Powerex recommends that the Commission be very specific in describing the types of multiple transmission requests it believes to be a problem and the fee structure that would be applied to such problematic requests. For example, Powerex believes the Commission should clarify that requests subject to the fee must be multiple, not pre-confirmed, and with identical quantity, point of receipt, point of delivery, start time, end time, and firmness. In its reply comments, Santa Clara disagrees with Powerex. Santa Clara urges the Commission to examine the practice of queue hoarding and punish those entities that are acting in an anticompetitive and manipulative manner. Further, Santa Clara urges the Commission to refrain from being too specific in its ruling, as a more general explanation of the behavior to be avoided would go a long way in preventing entities from making an end-run around a ruling against queue hoarding.

1364. MidAmerican believes that if a fee is imposed, the fee should not be refunded as the administrative costs and difficulty of administering the refunds would be an unreasonable burden on the transmission provider. CREPC believes refunding or crediting the processing fee would defeat the purpose of having one in the first place, although the processing fee could be refunded if the duplicative service request attached to it actually comes to fruition. Suez Energy NA suggests that the processing fee be refunded whenever the transmission provider exceeds the 60-day request study due diligence deadline. TAPS suggests that the fee be structured to provide for exceptions where the failure to confirm reflects a legitimate purpose, not jamming. TAPS cites as examples transmission requests associated with requests for proposals, alternative sites for planned generation, and the inability to secure timely confirmation of all legs of a multi-system path. TAPS notes that the current *pro forma* OATT accommodates multiple submissions in relation to the same competitive solicitation in sections 19.2(ii) and 32.2(ii).

Commission Determination

1365. The Commission will not require transmission providers to charge a fee for duplicative requests for transmission service. We will instead first consider whether the newly adopted NAESB queue flooding and queue hoarding business practices reduce the number of requests that the transmission customer does not intend to confirm. We are concerned that benefits to market participants would not justify the administrative costs of a new fee if the NAESB business practices can effectively discourage transmission service requests the transmission customer does not intend to confirm. We also believe that the current deposit mechanism in section 17.3 of the *pro forma* OATT should have the same effect as a fee based on the transmission provider's cost to process the request for transmission service, like the fee MISO and CREPC propose. Pursuant to section 17.3, in the event a transmission customer retracts or withdraws a request, the transmission provider is allowed to deduct from the transmission customer's deposit the costs the transmission provider incurred to process the request. As a result, we do not believe any other fee structure is necessary to make the transmission provider whole when a transmission customer submits a transmission service request it does not expect to confirm.

1366. A transmission provider that continues to experience problems related to submission of multiple duplicative requests for transmission service is free to file a tariff modification that includes a fee to combat the problem. This filing should explain why the transmission provider is unable to handle the submission of multiple duplicative requests for transmission service through NAESB's queue hoarding and queue flooding business practices.

(5) Clustering Transmission Service Request Studies

NOPR Proposal

1367. In the NOPR, the Commission sought comment regarding whether a transmission provider should be required to study requests for transmission service in a group if the transmission provider fails to complete studies on a timely basis. If so, the Commission sought comment on the circumstances that should trigger such a requirement and the appropriate method of implementing the requirement. The Commission sought further comment regarding whether transmission providers should be required to study requests for transmission service in a group if all the transmission customers in the group agree to cluster their requests. Finally, the Commission sought comment regarding how to select the requests that belong to a cluster so that transmission customers cannot ''cherry-pick'' clusters to avoid transmission system upgrade costs.

Comments

1368. A few commenters, primarily transmission customers, believe transmission providers should be required to study requests for transmission service in a group.[819] CREPC believes transmission providers should have the discretion to develop the criteria for clustering so that transmission customers do not have the opportunity to ''cherry pick'' study clusters. If transmission providers are required to study requests in a group, Powerex believes customers should be

[815] *E.g.*, EEI, Nevada Companies, Powerex, and Suez Energy NA.

[816] *E.g.*, EEI, Powerex, Suez Energy NA, and Entegra.

[817] *E.g.*, EEI and TAPS.

[818] *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,269 (2001) (rejecting a proposal to include a fee for non-confirmed transmission service requests for firm point-to-point transmission service of one week or longer).

[819] *E.g.*, CREPC, Powerex, and Suez Energy NA.

given the option of paying the transmission provider to perform an individual study. Suez Energy NA believes studying requests that are clustered voluntarily will partially incorporate the value of counterflows in the study process. PGP believes transmission customers should have the opportunity to join a cluster, but only if the customer is bound to accept the study results.

1369. A number of commenters, primarily transmission providers, state that transmission providers should be allowed, but not required, to study requests for transmission service in a group.[820] Bonneville argues that the transmission provider is in the best position to determine whether requests should be studied individually or in groups. EEI asserts that clustering does not necessarily ensure timely completion of transmission studies. FirstEnergy believes each transmission service request should stand on its own merits and be directly assigned costs associated with its own request so that requests in one part of the request queue do not end up subsidizing requests in another part of the request queue. MISO believes giving the transmission provider discretion to cluster requests will address the Commission's concerns with respect to transmission customers cherry-picking clusters to avoid paying upgrade costs. Arkansas Commission and East Texas Cooperatives suggest that the Commission allow clustering through an open season procedure similar to the procedure SPP currently uses pursuant to Attachment Z of SPP's OATT.

Commission Determination

1370. The Commission will not require transmission providers to study transmission requests in a cluster, although we encourage transmission providers to cluster request studies when it is reasonable. We do, however, require transmission providers to consider clustering studies if the customers involved request the cluster and the transmission provider can reasonably accommodate the request. We believe clustering request studies offers potential benefits as the needed transmission upgrades are frequently large enough that the upgrade can accommodate more than one transmission service request. In addition, jointly modeling transmission service requests can allow the transmission provider to more efficiently design transmission system upgrades. Clustering also allows the transmission provider to include, to the extent it is consistent with good utility practice, the potential counterflows created by the clustered requests. We do not agree, as suggested by commenters, that clustering necessarily leads to one set of transmission customers subsidizing another set of transmission customers.

1371. We therefore require each transmission provider to include tariff language in its compliance filing that describes how it will process a request to cluster request studies and how it will structure the transmission customers' obligations when they have joined a cluster. We will give the transmission provider discretion to determine whether a transmission customer can opt out of a cluster and request an individual study. We are giving each transmission provider discretion to develop the clustering procedures it will use because we believe the transmission provider is in the best position to determine the clustering procedures that it can accommodate. We also believe that the transmission provider is in the best position to develop a clustering procedure that prevents a transmission customer from strategically selecting the clusters in which it participates in an attempt to avoid responsibility for needed transmission system upgrades.

(6) Standardization of Business Practices for Study Queue Processing

NOPR Proposal

1372. In the NOPR, the Commission sought comment on whether additional standardization of request queue processing is necessary. If so, the Commission sought comment on the specific issues commenters believe are not clearly prescribed in Order No. 676 or the NOPR and that require additional mandatory queue processing business practices.

Comments

1373. Several commenters identified issues where a transmission customer needs coordinated responses across several transmission systems in order to serve its load.[821] Seattle and NRECA suggest that the Commission amend the *pro forma* OATT so that a customer's applications for service across multiple systems that are intended to serve a single sink from an identified resource will be considered a single application for purposes of establishing the deadlines for rendering an agreement for service, revising queue status, eliciting deposits and finally commencing service. Seattle believes the Commission should permit coordination and implementation of these requirements by a third party such as wesTTrans.net and sub-regional planning organizations. At a minimum, these commenters ask the Commission to develop business practices to protect a transmission customer caught between two systems with uncoordinated deadlines.

1374. Exelon states that the Commission should require all transmission providers to allow transmission customers to link consecutive requests for service (*e.g.*, monthly firm service requests for December, January and February) and to evaluate such request as a single request. Exelon argues that this service, which is currently provided by some transmission providers, would increase uniformity and use of the transmission system, and enhance competitiveness without burdening transmission providers or adding administrative complexity.

1375. TDU Systems indicate that several of its members have experienced difficulty related to the lack of standardized business practices, particularly in practices related to timing, application requirements, and requirements relating to methods of proving that a network customer has executed a power purchase agreement prior to designating the power purchase agreement as a network resource.

1376. PNM–TNMP does not believe that additional clarity or business practices are necessary beyond those already provided in Order No. 676. However, to the extent additional issues arise, PNM–TNMP believes NAESB's WEQ forum is the appropriate place to address them. Similarly, NorthWestern recommends that transmission providers work together within regional groups to develop a common set of business practices that will be followed by all transmission providers within each region, instead of the Commission using the NOPR comments it receives to develop a prescriptive set of business practices by which all transmission providers must abide. In its reply comments, Powerex argues that either the entire transmission process has to be integrated via an RTO, or coordination of requests across multiple control areas has to be done transmission provider by transmission provider. Powerex suggests that NorthWestern's suggestion for regional development of business practices may be a more pragmatic approach to address concerns about coordination of requests across multiple systems.

[820] *E.g.*, Bonneville, EEI, MISO, Nevada Companies, Southern, Entegra, and PNM–TNMP.

[821] *E.g.*, NRECA, TDU Systems, and Seattle.

Commission Determination

1377. The Commission agrees that transmission requests across multiple transmission systems should be coordinated by the relevant transmission providers. We will not, however, amend the *pro forma* OATT to require such coordination. Rather, we require transmission providers working through NAESB to develop business practice standards related to coordination of requests across multiple transmission systems. In order to provide guidance to NAESB, we will articulate the principles that should govern processing across multiple systems. All the transmission providers involved in a request across multiple systems should consider a request that requires studies across multiple systems to be a single application for purposes of establishing the deadlines for rendering an agreement for service, revising queue status, eliciting deposits and commencing service. In order to preserve the rights of other transmission customers with studies in the queue, the priority for the single application should be based on the latest priority across the transmission providers involved in the multiple system request. We note that regional entities like wesTTrans are already coordinating requests across multiple transmission systems and we believe such coordination is an acceptable solution to this issue.

1378. We interpret Exelon's request that we require all transmission providers to allow transmission customers to link consecutive requests for firm point-to-point transmission service and to evaluate such requests as a single request as asking us to (1) allow transmission customers to require the transmission provider to either grant service for the entire period, deny service for the entire period, or offer the same partial quantity for the entire period and (2) require the transmission provider to consider the full duration of the linked requests when determining reservation priority pursuant to sections 13.2 of the *pro forma* OATT (short-term firm point-to-point transmission service). We require transmission providers working through NAESB to develop business practice standards to allow a transmission customer to rebid a counteroffer of partial service so the transmission customer is allowed to take the same quantity of service across all linked transmission service requests. Transmission providers need not implement these business practice standards until NAESB develops appropriate standards. We note that the transmission customer should not be required to take the same quantity of service across consecutive transmission service requests, it should simply have the option to do so. On the second issue, we reiterate that, according to existing NAESB business practice standard 001–4.16, the transmission provider is required to consider the full duration of the linked requests when determining reservation priority pursuant to section 13.2 of the *pro forma* OATT.

1379. We believe most of the standardization issues TDU Systems raise (application requirements, requirements relating to methods of proving that a network customer has executed a power purchase agreement prior to designating the power purchase agreement as a network resource, and timing) have been addressed in this Final Rule. In particular, we describe the information a network customer is required to provide when designating a new network resource in section V.D.6.b of this Final Rule. We also indicate in section V.D.6.b that the transmission provider is not allowed to require a network customer to provide contract terms and conditions when it designates a power purchase agreement as a network resource. The network customer is required to provide a statement that attests, among other things, that it has executed a power purchase agreement prior to confirming its request to designate a new network resource. We will continue to give transmission providers discretion in determining whether to impose restrictions on the earliest time at which it will accept a request for transmission service. We believe the transmission provider is in the best position to determine whether it needs to restrict the time at which it will accept requests for transmission service in order to process transmission service requests in an orderly fashion consistent with the requirements in the *pro forma* OATT.

(7) Additional Processing Proposals

Comments

1380. A number of commenters propose changes to queue processing requirements that were not addressed in the NOPR.

1381. Powerex believes that OASIS practices should be modified to ensure that short-term firm and non-firm point-to-point service requests are processed based on the ATC posted at the time the requests were queued. Powerex argues that a transmission provider should not be permitted to grant transmission service requests at a time when its OASIS indicates there is no ATC. In its view, any such requests should be automatically denied. Powerex also suggests that confirmation time periods be shortened for short-term firm point-to-point service requests to discourage behaviors that have the effect of delaying queue processing. In its reply comments, Powerex asserts that requiring transmission provider responses to be based on posted ATC, as well as increasing standardization in transmission provider response time for short-term transmission requests, would enhance a transmission customer's ability to manage multiple transmission provider requests within the context of the *pro forma* tariff.

1382. Occidental suggests in reply that the Commission should introduce meaningful tariff-based sanctions for unauthorized deviations from the standards and modeling assumptions it proposes to include in Attachment C of the *pro forma* OATT, the transmission provider's description of its ATC calculation methodology.

1383. Several commenters make suggestions to allow the transmission provider to terminate idle transmission service requests. TDU Systems recommends that the Commission provide a sunset date by which all requests not pursued by the transmission customer would be terminated. MidAmerican and Northwest IOUs ask the Commission to clarify in the Final Rule that the transmission provider may deem a transmission service application withdrawn and terminated if a customer revises its application or if such customer fails to timely pay the annual reservation fee pursuant to section 17.7 of the *pro forma* OATT.

1384. Constellation asks the Commission to require transmission providers to release study results as soon as a study is completed, rather than holding them until the end of the 60 days.

1385. NorthWestern believes an appropriate modification to the study process would be to allow the transmission provider to have an opportunity to verify and correct the system impact study results at the beginning of the facilities study and again before construction begins.

1386. With the exception of very short-term transmission service (for which a bid-based system is impractical to manage), LDWP suggests that the queue process be transformed into a competitive process in which awards of transmission service are allocated in a manner similar to the provisions in section 4.4 of Order No. 638.

1387. TranServ notes that OASIS standards allow the customer to turn a request into a pre-confirmed request, but not vice versa. If the Commission's

proposal on granting priority to pre-confirmed requests is adopted, TranServ believes this capability should be removed from OASIS as it would seem to invite gaming and confuse transmission providers attempting to process requests in proper queue order.

1388. PGP states that OASIS platforms should be accessible from different computer platforms using a variety of browsers, not just one operating system/browser combination (Windows/Explorer), which is currently the case.

Commission Determination

1389. We will not adopt Powerex's proposal to require the transmission provider to accept or deny in all cases non-firm and short-term firm point-to-point transmission service requests solely based on posted ATC. The issue Powerex raises is ultimately a question of how the transmission provider is going to exercise its discretion under the tariff. Under the *pro forma* OATT, the transmission provider can use its knowledge of the system to exercise its discretion to offer transmission service even if posted ATC is not sufficient to accommodate the requested service. Alternatively, the transmission provider can use its discretion to update posted ATC in response to a transmission customer's verbal request to update ATC.[822] In both situations, the transmission provider may provide transmission service in instances when posted ATC is not sufficient to accommodate a transmission service request at the time the transmission customer requests service. We do not wish to discourage transmission providers from making transmission service available at times when posted ATC is not accurate. Therefore, we will continue to allow the transmission provider to accept transmission service requests in instances when posted ATC is not sufficient but the transmission provider believes it can accommodate the service. The transmission provider must use its discretion to grant service when posted ATC is not sufficient on a non-discriminatory basis. In order to ensure that it does so, we expect the transmission provider to log such instances as an act of discretion and post the log as required in section 37.6(g)(4) of the Commission's regulations.[823]

1390. We will not modify the *pro forma* OATT to address requests to allow the transmission provider to terminate idle transmission service requests. NAESB's business practice 001–4.11 allows the transmission provider to retract a request if the transmission customer does not respond to an acceptance within the time established in NAESB business practice standard 001–4.13. Therefore, we interpret TDU Systems comments to refer to circumstances when a transmission customer fails to respond to the transmission provider's request for additional information during the course of a request study. As discussed above, by the time the transmission provider offers a system impact study agreement, it should have all of the information that it needs to complete the study. Pursuant to section 17.4 of the *pro forma* OATT, the transmission provider can deem a transmission service request deficient if the transmission customer does not provide all of the information the transmission provider needs to evaluate the request for service. We will revise section 17.7 of the *pro forma* OATT so that the transmission provider is able to terminate a request for transmission service if a transmission customer that is extending the commencement of service does not pay the required annual reservation fee within 15 days of notifying the transmission provider that it would like to extend the commencement of service. We will not change the *pro forma* OATT to allow the transmission provider to terminate a transmission service request if the transmission customer changes its application for service. We believe the existing *pro forma* OATT is sufficient to allow a transmission provider to manage situations where the transmission customer modifies its application for service to the point that the customer is requesting transmission service that is meaningfully different than its initial request.

1391. We clarify that sections 19.3 and 32.3 of the *pro forma* OATT require the transmission provider to release study results as soon as a study is completed, rather than holding them until the end of the 60 days.

1392. Commenters also suggest changes to the OASIS protocols, including prohibiting transmission customers from changing a request into a pre-confirmed request and requiring OASIS platforms to be accessible on non-Windows/Explorer computers. We believe these issues are best addressed by NAESB.

1393. Commenters proposed a number of additional modifications to the *pro forma* OATT that we do not believe are necessary. These proposals would (1) allow the transmission provider to verify and correct studies between each step in the study process, (2) transform the queue process into competitive process, (3) shorten the confirmation time periods for short-term firm point-to-point service requests and (4) introduce penalties when the transmission provider deviates from the ATC calculation procedures detailed in Attachment C of the *pro forma* OATT. We believe the *pro forma* tariff is just and reasonable without such modifications and the commenters have not demonstrated that reforms in these areas are required at this time to prevent the exercise of undue discrimination.

b. Reservation Priority

1394. Section 13.2 of the *pro forma* OATT requires transmission providers to process requests for long-term firm point-to-point service on a first-come, first-served basis and to process requests for short-term firm point-to-point service on a first-come, first-served basis conditional on the duration of the request. Section 14.2 of the *pro forma* OATT requires transmission providers to process requests for non-firm point-to-point service on a first-come, first-served basis conditional on the duration of the request to the extent transmission capacity beyond that needed by native load customers, network customers and firm point-to-point transmission customers is available. In the NOPR, the Commission made a number of proposals and requested comment regarding various aspects of the reservation priority rules.

(1) Priority for Pre-confirmed Requests

NOPR Proposal

1395. In the NOPR, the Commission proposed to change the priority rules to give priority to pre-confirmed requests for firm point-to-point transmission service. Specifically, the Commission proposed that a pre-confirmed short-term request for firm transmission service would preempt any non-pre-confirmed short-term requests, regardless of duration. Similarly, the Commission proposed that a pre-confirmed request for long-term firm transmission service would preempt a request for long-term transmission service that is not pre-confirmed. Under the Commission's proposal, a pre-confirmed request for short-term transmission service would not pre-empt a non-pre-confirmed request for long-term transmission service.

Comments

1396. A number of commenters generally support the Commission's proposal to give priority to pre-

[822] *See, e.g., Florida Power Corp.*, 111 FERC ¶ 61,243 at P 5 (2005).

[823] 18 CFR 37.6(g)(4).

confirmed requests.[824] Commenters who support the proposal note that giving reservation priority to pre-confirmed requests for transmission service could help alleviate the problems that arise when a transmission customer submits multiple identical requests for service with no intention of confirming all accepted requests.[825] Supporters of the proposal also note that the proposal would allow the transmission provider to focus its attention on those requests that appear most likely to result in an actual reservation of transmission service.[826] Although Nevada Companies do not oppose the proposal, they note that concerns regarding withdrawal of pre-confirmed requests might otherwise be alleviated by requiring a non-refundable deposit on requests.

1397. Several commenters suggest that establishing reservation priority first based on pre-confirmation status and then based on duration would ultimately result in transmission customers with relatively shorter term requests getting transmission service instead of transmission customers with relatively longer term requests.[827] EEI asserts that this result would be inconsistent with the Commission's desire to promote longer-term uses of the transmission system. Several transmission providers suggest that the Commission modify its proposal to ensure that longer duration requests continue to have a priority over shorter duration requests.[828] EEI suggests that the Commission should use pre-confirmation as a tie-breaker for short-term requests for transmission service with the same duration. Southern argues further that a pre-confirmed daily or hourly request should not preempt a weekly request that has not been pre-confirmed.

1398. Opponents of the proposal identify a number of operational difficulties in implementing a system that gives priority to pre-confirmed requests. Several commenters note that transmission customers are not bound to take service because they pre-confirm a request for transmission service.[829] They argue, for instance, a transmission customer is not bound to take service in the event the transmission provider offers a study or counteroffers the request with a partial quantity of service. Similarly, MidAmerican notes that a transmission customer may withdraw a pre-confirmed request for transmission service at any time prior to acceptance by a transmission provider. Opponents also argue that giving priority to pre-confirmed requests would disrupt the study process.[830] This disruption would occur when a transmission provider receives a pre-confirmed request for transmission service while it is actively studying a request for service that has not been pre-confirmed. Under these circumstances, the transmission provider would be required to suspend the study of one request in order to study a request with a higher reservation priority. In its reply comments, Indianapolis Power asks the Commission to clarify if this interpretation of the NOPR proposal is accurate. TranServ, suggesting that the Commission has not proposed to give a priority to pre-confirmed requests for non-firm transmission service, asserts that having different priority rules for firm and non-firm transmission service introduces unnecessary complexity. Finally, Southern believes that a pre-confirmed service request submitted within close proximity to the actual commencement of service should not preempt an existing non-pre-confirmed request, if doing so would be disruptive to the operations of the transmission provider or to the reliability of the system itself.

1399. Opponents also argue that giving a priority to pre-confirmed requests would unfairly disadvantage transmission customers who are not in a position to pre-confirm their requests, such as those requesting service in response to a request for proposals.[831] EEI notes that the Commission addressed this issue when it issued Order No. 638 and decided that giving priority to pre-confirmed requests would disadvantage customers who are requesting service from multiple transmission providers.[832] In the event the Commission decides to proceed with its proposal, TAPS suggests that the Commission limit the priority for pre-confirmed requests to non-firm and short-term firm requests for transmission service.

1400. Several commenters question whether a request that has been accepted but not confirmed would be pre-empted by a new pre-confirmed request.[833] In a similar vein, TDU Systems suggests that the Commission include a time window between acceptance of a request and confirmation of the request, during which a request can not be preempted by a pre-confirmed request for transmission service.

Commission Determination

1401. The Commission generally agrees with those commenters that argue that giving a priority to pre-confirmed requests can increase the efficient utilization of the system by giving priority to customers who are committed to purchase service over those who have not so committed, including customers that submit multiple requests without any intent to take service if each request is granted. However, we are mindful of concerns that doing so could undermine the Commission's desire to promote longer-term uses of the transmission system, disrupt the study process, or disadvantage transmission customers that are not in the position to pre-confirm their requests. As a result, we will modify the NOPR proposal and give priority only to pre-confirmed non-firm point-to-point transmission service requests and short-term firm point-to-point transmission service requests. In addition, longer duration requests for transmission service will continue to have priority over shorter duration requests for transmission service, with pre-confirmation serving as a tie-breaker for requests of equal duration. This policy will still give an advantage to pre-confirmed requests without imposing substantial implementation difficulties or undermining the Commission's goals to encourage longer-term uses of the transmission system. Our revised policy on priority for pre-confirmed requests thus addresses the comments that we should preserve the priority of longer duration requests for transmission service over shorter duration requests for transmission service. For instance, a pre-confirmed daily or hourly request will not preempt a weekly request that has not been pre-confirmed. Pre-confirmed short-term service requests therefore will *not* have a priority superior to that of long-term service requests that have not been pre-confirmed.

1402. We acknowledge that our revised policy on priority for pre-confirmed requests may be less effective than the NOPR proposal in alleviating the problems that arise when transmission customers submit multiple identical requests for service. However, we have taken other steps—notably accepting the NAESB business practices on queue flooding and queue

[824] *E.g.*, Nevada Companies, Seattle, LDWP, PGP, PNM–TNMP, Salt River, and Suez Energy NA.

[825] *E.g.*, Ameren, Santa Clara, Entegra, Entergy, and TVA.

[826] *E.g.*, Ameren and NorthWestern.

[827] *E.g.*, CREPC and EEI.

[828] *E.g.*, Entergy, Southern, and NorthWestern.

[829] *E.g.*, Bonneville and EEI.

[830] *E.g.*, Bonneville, EEI, and MidAmerican.

[831] *E.g.*, EEI, MISO, TAPS, Constellation, and TDU Systems.

[832] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 638, 65 FR 17370, FERC Stats. & Regs., ¶ 1996–2000 ¶ 31,093 at 31,439 (2000).

[833] *E.g.*, MidAmerican and TranServ.

hoarding[834]—that we believe will substantially reduce the instances of multiple identical requests for service.

1403. The Commission also acknowledges the concerns expressed regarding operational difficulties caused by giving priority to pre-confirmed requests and clarify our policy as follows. First, we will prohibit transmission customers from withdrawing pre-confirmed non-firm and short-term firm point-to-point transmission service requests prior to when the transmission customer is offered service or a system impact study. This policy will address MidAmerican's concern that a transmission customer may withdraw a pre-confirmed request for transmission service at any time prior to acceptance by a transmission provider. We believe prohibiting withdrawal of a pre-confirmed request is less administratively burdensome than the non-refundable deposit on requests proposed by Nevada Companies and achieves the same goals. The Commission will allow transmission providers to invalidate a pre-confirmed request at the request of the transmission customer in the very near term following submittal of the request, in the event the transmission customer makes an inadvertent error in submitting its request. We expect the transmission provider to log such occurrences as an act of discretion so we can verify that transmission customers are not abusing this flexibility.

1404. Second, while the Commission recognizes that a customer submitting a pre-confirmed request is not bound to take service when the transmission provider counteroffers the transmission customer's initial request, we do not believe this fact alone warrants reversing our proposal to give a priority to pre-confirmed requests. We are satisfied that a transmission customer that pre-confirms its request is obligated to take full service in the event the transmission provider offers the service requested.

1405. The Commission also believes the revised priority policy will address Southern's comment that a pre-confirmed service request submitted within close proximity to the actual commencement of service should not preempt an existing non-pre-confirmed request if doing so would be disruptive to the operations of the transmission provider or to the reliability of the system itself. A pre-confirmed request for transmission service will not pre-empt an equal duration request that has already been confirmed. Therefore, the effects of the priority for pre-confirmed requests will be resolved prior to the time when the transmission provider would require an accepted request to be confirmed. Handling priority for pre-confirmed requests should be no more disruptive than giving a transmission customer time to confirm an accepted request.

1406. Excluding long-term requests for transmission service will mitigate many of the concerns expressed by commenters who argued that giving a priority to pre-confirmed requests will unfairly disadvantage transmission customers who are requesting service in response to a request for proposals and are therefore not in a position to pre-confirm their requests. Such requests for proposals typically involve long-term contracts for energy and/or generating capacity and, therefore, would be linked most likely to long-term transmission service requests. We disagree, however, with EEI's characterization of the Commission's decision in Order No. 638 to give a priority to pre-confirmed requests for non-firm service only if the request offers a higher price. The Commission's decision in that proceeding was driven by its interpretation that the proposed business practice addressed in the part of Order No. 638 cited by Southern was not consistent with the relevant section of the *pro forma* tariff. In addition, the Commission's experience since Order No. 638 and the comments received to the NOPR proposal indicate the value of giving a priority to pre-confirmed requests, despite concerns that some transmission customers are not in a position to pre-confirm their requests for transmission service.

1407. In response to requests for clarification from MidAmerican and TranServ, we clarify that a new pre-confirmed request for transmission service would preempt a request of equal duration that has been accepted by the transmission provider but not yet confirmed by the transmission customer. Thus, we decline to adopt TDU Systems' suggestion that the Commission include a time window between acceptance of a request and confirmation of the request, during which a request can not be preempted by a pre-confirmed request for transmission service. This is consistent with our desire to give transmission service first to those customers that are committed to taking the transmission service if it is granted. In the case of monthly firm point-to-point transmission service, the transmission customer has up to four days to confirm an accepted request. This is a potentially long delay when there is another transmission customer that is willing to commit to take the same service. Moreover, this policy is consistent with NAESB business standard 001–4.25, which allows a pre-confirmed request for non-firm point-to-point transmission service to preempt a request of equal duration and lower price that has been accepted but not confirmed.[835]

(2) Price as a Tie-Breaker

NOPR Proposal

1408. The NOPR also proposed to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. Under the Commission's proposal, price would serve as a tie-breaker after pre-confirmation for those requests that are not yet confirmed.

Comments

1409. All of the commenters who address the Commission's proposal to add price as a tie-breaker support the proposal, although some request that it be modified or clarified. Several commenters ask the Commission to clarify that an otherwise higher queued request has a right to match the price offer of a request with a higher price.[836] With regard to short-term service, WAPA believes that the Commission's proposal to add price as a tie-breaker would overly complicate matters after taking into account the many complex timing restrictions on short-term service. As a result, WAPA proposes that the Commission limit application of its proposal to requests for long-term transmission service. MISO/PJM States suggest that the Commission consider requiring point-to-point transmission customers to offer a reservation price at which they would be willing to sell their transmission service.

Commission Determination

1410. The Commission adopts the NOPR proposal to add price as a tie-breaker in determining reservation queue priority when the transmission provider is willing to discount transmission service. As a result, price will serve as a tie-breaker after pre-confirmation for those requests that have not yet been confirmed by the transmission customer or have not yet been evaluated by the transmission provider. Consistent with the principles currently embodied in the *pro forma* OATT and articulated in Order No. 638, we clarify that, in the event a later queued short-term request for

[834] *See* Order No. 676 at P 19.

[835] *See* Order No. 676.

[836] *E.g.*, EEI and MidAmerican.

transmission service preempts a conditional confirmed short-term request for transmission service based on price, then the conditional confirmed request has a right to match the price offer of the later queued request.[837]

1411. We disagree with WAPA's proposal to limit application of the NOPR proposal to requests for long-term transmission service. We believe the addition of price as a tie-breaker for discounted firm point-to-point transmission service is an economically efficient policy for both short-term and long-term firm point-to-point transmission service. We recognize that adding another element to the reservation priority criteria adds additional complexity. However, we believe that the efficiency gains warrant any additional complexity in the few cases in which transmission customers bid for transmission service.

1412. We do not agree with MISO/PJM States' suggestion that the Commission require point-to-point transmission customers to offer a reservation price at which they would be willing to sell their transmission service. The transmission provider may already make unscheduled firm transmission service available to other customers on a non-firm basis and we have adopted proposals that we believe will encourage transmission customers to voluntarily offer to sell firm point-to-point transmission service on the secondary market as described in section V.C.4 of this Final Rule. As a result, we see no reason to require a firm point-to-point customer to offer its reserved capacity for sale.

(3) Five-Minute Window for Requests

NOPR Proposal

1413. In the NOPR, the Commission responded to comments that transmission customers that have the financial resources to purchase software and employ staff to continually monitor OASIS sites have an unfair advantage under a first-come, first-served approach by seeking comment on whether any such advantage would be mitigated if all requests submitted within a five-minute window were deemed to have been submitted simultaneously. The Commission also sought comment on whether transmission customers could game a five minute equivalent priority standard to request transmission service only after another transmission customer has made a request. The Commission further sought comment on how to allocate limited transmission capacity among equivalent priority requests of equal duration, in the event a five minute equivalent priority standard is adopted.

Comments

1414. Many of the commenters in the West support the proposal to treat transmission requests submitted within some specified period of time as submitted simultaneously. Supporters of a time window within which all requests would be deemed to have been submitted simultaneously argue that the proposal would give transmission customers who are less sophisticated and have fewer financial resources equal access to transmission service.[838] Other supporters argue that such a time window would be particularly appropriate in circumstances when a tariff calls for requests to be submitted ''no earlier than'' a specific deadline.[839] In its reply comments, NRECA argues that a customer attempting to plan a request under such circumstances may miss being the first in time by a matter of seconds because its computer is slower than another customer's computer.

1415. Supporters of the proposal suggest a number of modifications to the Commission's suggested five-minute window. A number of commenters suggest a window longer than five minutes.[840] For instance, Bonneville proposes a system similar to PJM's 30 minute window for monthly service. On the other hand, Manitoba Hydro suggests a shorter window and a limit on the number and size of requests, claiming this would reduce the potential for gaming and/or anti-competitive behavior. A number of commenters also suggest that such a system should be limited to short-term transmission service[841] and/or should not apply to requests for transmission service submitted close to the hour that service commences.[842] In its reply comments, PNM–TNMP asserts that, if the Commission implements a five-minute window policy, then the policy should not be limited to long-term transactions. In its reply comments, NRECA argues that requests submitted within a five-minute window should not be publicly available until the window has closed in order to prevent competitors from requesting the same service simply to disrupt the transmission service procurement process. Similarly, Bonneville suggests that the reservation process should be conducted like a blind auction, so that requests are not visible on OASIS until the window closes.

1416. Many of the large power marketers and transmission providers in the East oppose the notion of a submittal window. Opponents of a time window within which all requests would be deemed to have been submitted simultaneously suggest that the proposal is an unnecessary complication and may actually be counterproductive to the Commission's ultimate goal due to issues regarding how transmission service would be allocated among simultaneous requests.[843] EEI notes that there is no limit on how far in advance a transmission customer may submit requests for firm transmission service, so the likelihood that any two requests are submitted within the same five minute period is low. Powerex argues that the simplicity of the first-come, first served approach limits the number of disputes. In its reply comments, Powerex argues that none of the commenters that favor a five-minute window addressed the operational problems that such a proposal would generate.

1417. Some commenters argue that a *pro rata* allocation of simultaneous requests of equal duration will result in all transmission customers acquiring less transmission service than they need to complete their wholesale transactions.[844] As a result, these commenters suggest that the need to provide transmission customers with usable quantities of transmission service will necessarily lead to developing an allocation protocol in addition to allocating based on time submitted and duration of request.[845] Powerex argues that any system that creates a time window within which all requests would be deemed to have been submitted simultaneously will lead transmission customers to inflate the quantity of service they request in order to get quantity of service they actually desire. Other commenters make suggestions regarding the manner by which transmission service should be allocated among simultaneously submitted requests. Bonneville believes that each transmission provider should develop an allocation method appropriate to its system. CREPC suggests that price be used as a secondary tie-breaker after duration. TDU Systems argue that using duration

[837] *See* Order No. 638 at 31,442.

[838] *E.g.*, Bonneville and Santa Clara.

[839] *E.g.*, TDU Systems and NRECA.

[840] *E.g.*, Bonneville and CREPC.

[841] *E.g.*, Bonneville and Nevada Companies.

[842] *E.g.*, Bonneville and NRECA.

[843] *E.g.*, EEI, MidAmerican, Ameren, Constellation, Entergy, NorthWestern, PNM-TNMP, WAPA, Powerex, and Indianapolis Power Reply.

[844] *E.g.*, Powerex and TranServ.

[845] *Id.*

as a tie-breaker for simultaneous requests could discriminate against purchased power contracts that are designated as network resources.

Commission Determination

1418. Based on the comments received, it appears that the desire for a time window within which all requests would be deemed to have been submitted simultaneously is largely limited to market participants in the Western Interconnection. With one exception, we will not mandate a change to our current first-come, first-served policy to address an issue that appears to be regional in nature. Rather, we will allow transmission providers to propose a window within which all transmission service requests the transmission provider receives will be deemed to have been submitted simultaneously. Transmission providers will have discretion to determine which transmission services will be subject to a submittal window policy. We believe the transmission provider is in the best position to determine whether it can accommodate a submittal window for a specific transmission service and the need for such a window.

1419. In order to ensure that transmission service is not awarded in an arbitrary fashion and to ensure that transmission customers who are less sophisticated and have fewer financial resources have equal access to transmission service, we will require transmission provider who set a ''no earlier than'' time for request submittal to treat all transmission service requests received within a specified period of time as having been received simultaneously. We agree with those commenters that argue that a time window within which all requests would be deemed to have been submitted simultaneously is particularly appropriate in circumstances when a tariff or business practice calls for requests to be submitted no earlier than a specific deadline. As NRECA argues, there is no meaningful difference between requests for transmission service that are identical in all respects except that one request is received by the transmission provider seconds ahead of another request because one customer's computer is slower than another customer's computer. EEI is correct that NAESB's uniform business practices do not limit how far in advance a transmission customer may submit requests for firm transmission service.[846] However, a number of transmission providers have modified their tariffs or adopted business practices that mandate that requests can be submitted no earlier than a specific deadline.[847] In these instances, multiple requests for transmission service can be submitted at approximately the same time. We generally agree with Powerex's assertion that the simplicity of the current first-come, first served approach limits the number of disputes. However, when a transmission provider establishes a ''no earlier than'' deadline, submittals that are received by the transmission provider within a matter of seconds cannot be meaningfully differentiated. A transmission provider with such a business practice or tariff provision will be required to modify its tariff to include its proposed specified period of time. We will evaluate each proposal on a case-by-case basis, as described below.

1420. We will allow transmission providers to propose the period of time within which all requests would be deemed to have been submitted simultaneously. We believe the transmission provider is in the best position to identify the window it can operationally accommodate. We expect the submittal window to be open for at least five minutes unless the transmission provider can present a compelling rationale to justify a shorter submittal window.

1421. We agree with NRECA and Bonneville's suggestion that requests submitted within a specified window should not be publicly available until the window has closed in order to prevent competitors from requesting the same service simply to disrupt the transmission service procurement process.

1422. We will require each transmission provider that is required to, or decides to, deem all requests submitted within a specified period as having been submitted simultaneously to propose a method for allocating transmission capacity if sufficient capacity is not available to meet all requests submitted within the specified time period. We agree with Bonneville that the transmission provider is in the best position to determine an allocation that is appropriate to its system and that cannot be gamed in the manner suggested by Powerex and TranServ. We believe that transmission providers will be able to develop allocation methods, like the method PJM uses to allocate monthly firm point-to-point transmission service, that address the operational issues Powerex and TranServ raise.

(4) Right of First Refusal and Preemption

1423. While not specifically addressed in the NOPR, a few commenters use the Commission's proposed introduction of hourly firm service, discussed above, to argue that the Commission should take the opportunity to clarify or revise the right of first refusal for short-term transmission service requests.

1424. To understand commenter concerns, it is useful to note the relevant components of the reservation and scheduling process in the *pro forma* OATT. Reservations for short-term firm point-to-point transmission service are available on a first-come, first-served basis and are conditional based upon the length of the requested transaction as explained further below. If the transmission system becomes oversubscribed, longer-term service may preempt shorter-term service, up to a specified period. The shorter-term reservation holder has a right of first refusal to match the longer-term reservation, but such right must be exercised within 24 hours of being notified of the competing reservation, or earlier to comply with the scheduling deadline.

Comments

1425. Salt River argues that the time required to administer the right of first refusal—which includes contacting customers and allowing time to exercise the right of first refusal—is overwhelming. Salt River argues that the current OASIS business practices do not permit adequate time to implement these rules, and the industry lacks the software to either streamline the effort or ensure quality control. Salt River contends that for hourly, daily, and weekly requests, the complexity and potentially unjust results of administering preemption and the right of first refusal rules outweighs any potential benefits. Accordingly, Salt River recommends revisions to the *pro forma* OATT that make the right of first refusal available only to monthly requests for service.

1426. To address the complications arising from preemption and the right of first refusal, Duke proposes several revisions to the *pro forma* OATT: only

[846] *See* NAESB Business Practice Standard 001–4.13.

[847] For instance, Idaho Power Company has adopted a business practice that requests for monthly firm transmission service cannot be submitted earlier than 11 months prior to operation. Portland General Electric has adopted a business practice that Daily Firm ATC on the California-Oregon Intertie will be posted at or about 7:11 a.m. Pacific on the day prior to operation and that requests that are submitted prior to ATC being posted will be refused. SPP has modified its tariff so that requests for monthly firm transmission service cannot be submitted more than 90 days prior to the first day of operation.

pre-confirmed requests would trigger preemption; confirmed requests could not be displaced by longer-term requests; only monthly customers subject to preemption would be given a right of first refusal (Salt River proposes a similar OATT revision); and, profiled requests (*i.e.*, requests for transmission that may have different MW values for each hour of the day, and may even include some hours where the MW value is zero) would not be granted priority over confirmed reservations. TranServ also asks the Commission to provide guidance establishing the earliest and latest submission times and maximum successive or consecutive terms of service required. TranServ contends it is unreasonable that a request for daily firm service could be submitted years in advance and then have a right of first refusal to match any longer-term request for service.

1427. To eliminate the potential for more complexity, TranServ requests that the Commission eliminate the conditional nature of short-term point-to-point service under the OATT. Whether the Commission adopts this recommendation, TranServ further recommends that the Commission revise the timing provisions for requesting short-term point-to-point service to reduce overlap for submission of requests that would trigger the need for preemption. TranServ and Duke recommend a reservation or bidding process in which one increment of service (monthly, weekly, daily, and hourly) is available at a time, with each successive shorter increment of service becoming available after the reservation or bidding window for the preceding longer increment has closed.

1428. NorthWestern requests that the Commission clarify whether the terms ''reservation'' and ''request'' used in section 13.2 (Reservation Priority) are used interchangeably. If they are not used interchangeably, and ''reservation'' is meant to be a confirmed request, while ''request'' is a queued request that has not been confirmed, NorthWestern suggests that the sentence that includes the two uses of ''reservation'' creates confusion because, if both requests are confirmed, then either sufficient capacity exists to accept both requests, or the transmission provider accepted requests that exceed the ATC. To avoid confusion, then NorthWestern recommends that the second use of ''reservation'' should be changed to ''request.'' If so, to avoid the suggestion that the section is attempting to distinguish between requests that have been confirmed from those simply queued, NorthWestern recommends that the Commission consider changing all of the ''reservation'' references to ''request.''

Commission Determination

1429. Based on the issues raised in comments, we find that changing the ''first come, first served'' nature of the reservation process and right of first refusal process is not warranted at this time. The ''first-come, first-served'' principle facilitates the administration of the reservation process and benefits customers because there can be little confusion about how to comply with it.

1430. The remaining concerns regarding administering the right of first refusal are addressed below. First, when a longer-term request seeks capacity allocated to multiple shorter-term requests, the shorter-term customers should have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price, and time of response would then be used to determine which of the shorter-term requests will be able to exercise the right of first refusal, consistent with the Commission's tie breaking provision in section 13.2(ii). Second, to minimize the potential for gaming, a preempting longer request must be for a fixed capacity over the term of the request.

1431. We agree with NorthWestern's assertion that the sentence in section 13.2(iii) of the *pro forma* OATT that includes the two uses of ''reservation'' creates confusion. Therefore, we clarify that the terms ''reservation'' and ''request'' are not used interchangeably; ''reservation'' is meant to be a confirmed request, while ''request'' is a queued request that has not been confirmed. To clarify the distinction between use of the terms ''request'' and ''reservation'' in section 13.2(iii), we will revise that section so that the sentence ''Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter-term service has the right of first refusal to match any longer-term *reservation* before losing its reservation priority'' is replaced by the sentence ''Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter-term service has the right of first refusal to match any longer-term *request* before losing its reservation priority.''

6. Designation of Network Resources

a. Qualification as a Network Resource

1432. Taken together, the following sections of the *pro forma* OATT describe the resources a network customer can appropriately designate as a network resource. Section 30.1 of the *pro forma* OATT describes network resources as all generation owned or purchased by the network customer designated to serve network load under the tariff. Section 30.1 also indicates that network resources may not include resources that are committed for sale to non-designated third-party load or otherwise cannot be called upon to meet the network customer's network load on a noninterruptible basis. Pursuant to section 30.7 of the *pro forma* OATT, the network customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a network resource. Alternatively, the network customer may establish that execution of a contract is contingent upon the availability of network service. Section 29.2 requires the network customer to provide the following information about a power purchase agreement that is to serve as a new designated network resource: source of supply, control area location, transmission arrangements and delivery point(s) to the transmission provider's transmission system.

1433. As the Commission noted in the NOPR, a number of orders address what types of resources meet the criteria set out in sections 30.1 and 30.7 of the *pro forma* OATT. In *MSCG*, the Commission stated that network resources must be generating resources owned by the network customer or purchases of noninterruptible power under executed contracts that require the network customer to pay for the purchase.[848] In *WPPI*, the Commission found that a network customer can designate as a network resource a system purchase that is not backed by a specific generator.[849] The Commission found that Wisconsin Public Service Corporation (WPS) had appropriately designated a power purchase as a network resource, even though the power purchase agreement did not require WPS to take energy around the clock and allowed WPS to convert its energy purchase to a discounted product that could be interrupted.[850] In addition, the Commission stated that, because the *pro forma* OATT requires a power purchase to be noninterruptible, third-party transmission arrangements to deliver the resource to the network have to be

[848] *Morgan Stanley Capital Group* v. *Illinois Power Co.*, 83 FERC ¶ 61,204 at 61,911–12 (1998), *order on reh'g*, 93 FERC ¶ 61,081 (2000) (*MSCG*).

[849] *Wisconsin Public Power Inc.* v. *Wisconsin Public Service Corp.*, 84 FERC ¶ 61,120 at 61,650–51 (1998) (*WPPI*).

[850] *Id.*

noninterruptible as well.[851] In *Illinois Power*, the Commission found that a firm purchase need not be backed by a capacity purchase to qualify as a network resource.[852]

NOPR Proposal

1434. In the NOPR, the Commission proposed to maintain its current policy regarding the power purchase agreements that network customers may designate as network resources. In particular, the Commission proposed that a network customer would continue to be able to designate resources from system purchases not linked to a specific generating unit, provided the power purchase agreement is not interruptible for economic reasons, does not allow the seller to fail to perform under the contract for economic reasons, and requires the network customer to pay for the purchase. In addition, the Commission reiterated that third-party transmission arrangements to deliver the purchase to the network must be noninterruptible.

1435. Regarding seller's choice contracts, the Commission explained that a power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) of the *pro forma* OATT cannot be designated as a network resource. Specifically, the Commission reiterated that a request to designate a new network resource must provide the information including the source of supply, control area location, transmission arrangements, and delivery point(s) to the transmission provider's transmission system. The Commission proposed that, when designating a system purchase as a new network resource, a network customer must identify the resource as a system purchase as well as the control area from which the power will originate.

1436. In response to suggestions that liquidated damages (LD) products should not be designated network resources because they are interruptible for economic reasons, the Commission proposed to clarify that network customers may not designate as network resources those power purchase agreements that give the seller a contractual right to compensate the buyer instead of delivering power even if the seller is able to deliver power. For instance, the Commission proposed that a network customer may not designate as a network resource a purchase agreement that allows the seller to interrupt sales under the purchase agreement for reasons other than reliability, but allows the buyer to force delivery at a higher price. In addition, the Commission proposed that a network customer may not designate as a network resource a purchase agreement that requires a seller to pay the buyer's cost of replacement power when the seller chooses not to deliver energy for economic reasons.

Comments Overview

1437. Most commenters argue that the Commission must provide further clarification than given in the NOPR, particularly with regard to the eligibility of firm LD power products and the information required by section 29.2(v) of the *pro forma* OATT for seller's choice contracts. Various commenters also argue that the Commission's precedent on this issue is contradictory and that the Commission's policy with respect to designation of network resources may violate section 217 of the FPA and conflict with state jurisdiction.

(1) LD Contracts

Comments

1438. Many commenters express general support for some or all of the Commission's clarifications in the NOPR with regard to ineligibility of resources which are interruptible for economic reasons and/or that allow the seller to compensate the buyer instead of delivering power even if the seller is able to deliver power.[853] However, many commenters express concern about the clarity of the policy.[854]

1439. In particular, several parties contend that it is in fact the firmness of the contract and not the mere existence of an LD provision describing the remedies in case of a failure to perform that determines the eligibility of a power purchase agreement to be designated as a network resource.[855] TAPS argues that, in order to determine the firmness of a purchase, one must look at the criteria for excusing a failure to supply. AMP-Ohio, MISO, and NCPA also express support for this position, pointing to the Commission's finding in *Dynegy*[856] that the inclusion of an LD provision in EEI's Master Power Purchase and Sale Agreement's Firm LD product (EEI's Firm LD Product) does not inherently make that product less firm.

1440. Several commenters argue that, when the Commission in *Dynegy* considered the acceptability of EEI's Firm LD Product as a designated network resource, it neglected to consider the presence of a provision which appears to contradict its decision.[857] They point to the Commission's statement in *Dynegy* that EEI's Firm LD Product ''does not permit the power to be interrupted for economic reasons, or at the discretion of either party, but only if a force majeure occurs.''[858] Some contend that the Commission's conclusion ignored the fact that EEI's Firm LD Product actually allows power to be interrupted for *any* reason, including economic reasons, after which the agreement then provides LDs as a remedy if the interruption was not due to a force majeure event.[859] Duke and EEI note that contracts under EEI's Firm LD Product agreement or similar agreements have become commonplace since the Commission's *Dynegy* decision and that clarification regarding their use as network resources is required to address industry confusion.

1441. Several commenters disagree that the EEI Firm LD Product gives parties the right to interrupt for any reason, including economic reasons, provided that LDs are paid by the non-performing party.[860] Hoosier argues on reply that EEI and Southern have misunderstood the Commission's intent in *Dynegy*. Hoosier contends that the Commission correctly found in *Dynegy* that the EEI Firm LD Product does not permit power to be interrupted for economic reasons, or at the discretion of either party, but only if a force majeure event occurs. Thus, Hoosier argues, the EEI Firm LD Product does not give the seller a *right* to interrupt for any reason other than force majeure, and any seller that interrupts for economic reasons is clearly in breach of its obligations to perform under the contract and must

[851] *Id.* at 61,660.

[852] *Illinois Power Co.*, 102 FERC ¶ 61,257 at P 14 (2003), *reh'g denied*, 108 FERC ¶ 61,175 (2004) (*Illinois Power*).

[853] *E.g.,* Ameren, BART, Constellation, Duke, Entegra, Entergy, Morgan Stanley, MISO, NorthWestern, Progress Energy, Sempra Global, Southern, Suez Energy NA, and TranServ.

[854] *E.g.,* AMP-Ohio, APPA, Duke, EEI, Entergy, Fayetteville, Morgan Stanley, NCPA, Northwest IOUs, Northwest Parties, MISO/PJM States, PGP, Pinnacle, PNM–TNMP, Salt River, Sempra Global, Southern, TAPS, Utah Municipals, and WSPP.

[855] *E.g.,* AMP-Ohio, Northwest IOUs, NRECA Reply, PGP, Pinnacle, Sempra Global, Strategic Energy Reply, and TAPS.

[856] *Dynegy Midwest Generation*, 101 FERC ¶ 61,295 (2002), *reh'g dismissed*, 108 FERC ¶ 61,175 (2004) (*Dynegy*).

[857] *E.g.,* Duke, Dynegy Reply, EEI, and Southern.

[858] *Dynegy* at P 21.

[859] *E.g.,* Duke, EEI and Southern. EEI notes that its Firm LD Product is distinct from its ''System Firm'' and ''Unit Firm'' products in its Master Power Purchase and Sale Agreement, each of which excuses a failure to perform only for force majeure and neither of which permits a party to fail to perform and pay liquidated damages.

[860] *E.g.,* Hoosier Reply, Strategic Energy Reply, and Utah Municipals.

pay damages. Hoosier acknowledges that a seller always has the choice of not performing its obligations and paying damages, but that is not peculiar to the EEI Firm LD Product. Hoosier maintains that any party to any contract has the *ability*, but not the *right*, to breach its obligations under the contract and pay damages. According to Hoosier, the only difference in the case of the EEI Firm LD Product is that the parties have stipulated beforehand as to the measure of the damages required of a seller in breach, in order to minimize litigation over damages. This stipulation, Hoosier argues, conveys no additional substantive rights on either party.

1442. Several parties note that firm LD contracts account for a significant number of currently utilized products and that disallowing these product to be designated as network resources may create significant disruption.[861] Commenters supporting continued use of firm LD contracts as designated network resources argue that allowing products structured on EEI's Firm LD Product has not created reliability problems.[862] Southern argues that the Commission should not set criteria that would place in jeopardy an array of products that have a firm LD dimension. Southern further states that such products are among the most reliable in instances where market prices are very high (where LDs could be quite substantial) and that just about any power purchase/sale contract can be financially settled in real-time or for a given period in lieu of physical delivery during that period. The fact that some contracts set out in advance the terms of such settlement (so to render commerce more efficient and liquid) does not, Southern argues, render those contracts any less qualified for designation as network resources. Thus, Southern encourages the Commission to reconsider its revised guidance regarding the ineligibility of contracts structured after EEI's Firm LD Product. Utah Municipals agrees, and similarly requests that contracts under EEI's Firm LD Product be allowed to qualify as network resources.

1443. Morgan Stanley argues that the notion that firm LD contracts do not contribute as much to resource adequacy as contracts tied to individual physical resources is inaccurate. Morgan Stanley contends that the incentive to ensure performance is far greater with a firm LD obligation than with unit contingent and system firm contracts. Morgan Stanley explains that unit contingent and system firm contracts require delivery if the unit or group of units performs and excuses delivery if they do not, while a Firm LD obligation requires delivery so long as it is physically possible to achieve delivery, regardless of the cost of doing so. Thus, according to Morgan Stanley, firm LD products can enhance supply security because they are not dependent upon the performance of an individual unit or units, but rather put the burden and opportunity on the supplier to use multiple physical resources to meet its obligations.

1444. APPA also requests reconsideration of this issue, arguing that its members are often presented with power purchase agreements based on EEI's Firm LD Product and that they are not always successful in negotiating amendments to such agreements with suppliers. APPA argues that an LSE can use a diverse resource portfolio, including firm LD power purchase agreements, to serve its load economically, while meeting reliability requirements and advancing other important policy objectives (diverse fuel mix, use of renewable energy, *etc.*). APPA urges the Commission to allow such use if it is consistent with the commercial practices in a region.[863]

1445. NCPA also opposes forbidding firm LD products without looking more fully into their merits and the potential safeguards that could be built into them. NCPA recognizes that firm LD contracts raise certain issues under the *pro forma* OATT and also pose issues for planning where a specific resource is not designated, but these problems are not significantly different from the problems of a large transmission owner designating its entire fleet as network resources for its entire load. Rather than ban LD contracts from an important segment of the market, several commenters suggest that the Commission convene a separate proceeding or conference to further investigate the issue.[864]

1446. Other commenters argue against allowing the designation as network resources of contracts that permit the interruption of power sales for reasons other than reliability as long as LDs are paid.[865] Detroit Edison argues in its reply comments that a seller's decision to pay the ''costs of 'cover' '' under these contracts is of no value to an LSE that lacks deliverable alternatives. Detroit Edison further claims that, contrary to Southern's assumption that a failure to deliver under a firm LD contract would result in substantial non-delivery penalties, one would expect a supplier afforded the option to divert power to a higher priced market that produces a net financial gain would elect to interrupt service under the power sales contract and pay the LDs. Detroit Edison contends that purchasers would be left hanging during periods of supply shortage when firm physical supply is most critical.

1447. In its reply comments, Duke asserts that allowing firm LD products to be designated as network resources would result in network customers leaning on its system. Although it has doubts about whether the EEI Firm LD Product actually contains language that prohibits interruptions for economic reasons, Duke would find the inclusion of such language in purchased power agreements to provide sufficient firmness to allow the contract to be designated as a network resource. In its reply comments, Dynegy argues that allowing designation of firm LD products is simply inconsistent with the existing OATT requirements that a transmission customer either own, purchase or have rights to generation.

1448. Northwest IOUs request that the Commission clarify whether the limitations for qualification of a network resource, such as the presence or absence of an LD clause, would prevent a transmission provider from using such a resource for service to its bundled native load customers. Northwest IOUs state that, if the non-rate terms and conditions do not apply directly by requirement of the Final Rule, but only under a comparability test where there is a comparison to network customers, then that position should be made clear. They further note that some transmission providers have no comparable network service, or no service involving generating units within the transmission provider's control area. Accordingly, Northwest IOUs request that the Commission clarify whether, in those instances, the limitations for qualification of a network resource would apply.

1449. Many commenters also argue for the eligibility of service provided under the WSPP Service Schedule C (Schedule C) agreement.[866] In particular, WSPP argues that its Schedule C product satisfies the Commission's requirements for designation as a network resource because it requires the seller to deliver power except under very limited

[861] *E.g.,* APPA, Hoosier Reply, NCPA, Southern, Strategic Energy Reply, and Utah Municipals.

[862] *E.g.,* EEI, Hoosier Reply, Southern and NCPA.

[863] MISO/PJM States similarly argue that whether a particular contract with LD provisions can serve as a designated resource should be decided within the RTO stakeholder process.

[864] *E.g.,* APPA Reply, Morgan Stanley, and NCPA.

[865] *E.g.,* Duke, Dynegy, and Detroit Edison Reply.

[866] *E.g.,* APPA, EEI, Entergy, Northwest Parties, Salt River, Utah Municipals, and WSPP.

circumstances, such as force majeure, and that the agreement itself clearly provides that it is a firm product. However, WSPP notes that its product, like most if not all wholesale power sales contracts, contains a damages provision which could be characterized as an LD provision. WSPP contends that such provision is used simply to avoid the need to litigate damages and not to permit a seller to ignore its delivery obligations by financially settling a firm power sale. WSPP states that it is not intended that sellers be allowed to refuse to deliver for economic reasons. Therefore, WSPP requests clarification that its Schedule C product is eligible for designation as a network resource, and notes the potential for significant disruptions in the market and WSPP member sales of firm products if its Schedule C product is not considered eligible for designation as a network resource.

1450. EEI and Northwest Parties note that, in some instances, both the sellers and buyers of the Schedule C product designate that product as a network resource, since it appears to meet the *pro forma* OATT definition of a network resource for both parties because the agreement allows interruptions to serve native loads. If only one party is found to be able to designate the Schedule C product as a network resource, EEI argues that the other party would run the risk of civil penalties for making an incorrect attestation and may also lose the transmission rights that it needs to serve its native load or network load. Northwest Parties request specific clarification as to whether power purchased under Schedule C from a seller with public utility or statutory obligations to its customers is to be considered power available to meet the purchaser's network load on a non-interruptible basis, given that the seller may interrupt service under the power sales contract to meet its public utility or statutory obligations. If the Commission decides that the Schedule C transactions cannot be designated as network resources, Northwest Parties asks the Commission to state whether such transactions would be eligible if the WSPP service agreement requires the seller to give the purchaser advance notice of an interruption. Salt River also asks that, if Schedule C is found to be ineligible, the Commission identify the specific changes needed to that contract to allow for designation.

1451. Beyond the eligibility of contracts with LDs to be designated as network resources, EEI and Duke also argue that there is a conflict between the policy guidance given in *Dynegy* (that a power purchase agreement which is interruptible for reasons other than reliability is not eligible for designation as a network resource) and the guidance given in *WPPI*[867] (that a power purchase agreement which permits curtailment to serve the seller's native load is eligible for designation as a network resource). Duke argues that, since the type of contracts contemplated in *WPPI* are clearly interruptible for reasons other than reliability, *WPPI* should no longer be deemed valid case law in light of the Commission's proposed clarifications in the NOPR. Duke argues that allowing such contracts to be designated as network resources creates reliability risks and likely permits two entities to designate the same generation as network resources. While Duke acknowledges that exceptions to this rule may be necessary in the Western Interconnection, it does not support an exception for the Eastern Interconnection. EEI argues that the conflict between the *Dynegy* and *WPPI* standards has resulted in different transmission providers and customers using different standards for designation of network resources. EEI therefore asks the Commission to clarify precisely what contracts qualify as a network resource before it implements its proposed attestation requirement.

Commission Determination

1452. Many commenters seek clarification of the eligibility of power purchase agreements with LD provision to be designated as network resources. In clarifying our policy concerning firm LD products, we turn first to the apparent confusion surrounding the Commission's findings in *Dynegy*. Duke, *Dynegy*, EEI, and Southern argue that the Commission incorrectly found in *Dynegy* that the EEI Firm LD Product could not be interrupted for economic reasons. These parties argue that the EEI Firm LD product actually allows power to be interrupted for *any* reason, including economic reasons, after which LDs are assessed if the interruption was not due to a force majeure event. We disagree. As Hoosier points out, the EEI Firm LD Product does not permit power to be interrupted for economic reasons. While any party to any contract can choose to fail to perform, that does not convey a contractual right to fail to perform. The EEI contract clearly obligates the supplier to provide power, except in cases of force majeure. Thus, the contract does not *allow* interruption for economic reasons. The presence of an LD provision in the EEI Firm LD Product does not permit the seller to violate the terms of the contract, but rather merely specifies the damages that must be paid if the seller fails to perform under the contract. As noted by many commenters, it is the firmness of a power purchase contract, and not simply the presence or absence of an LD provision, that determines the eligibility of that power purchase to be designated as a network resource.

1453. We conclude, however, that the firmness of an obligation to provide under a contract with an LD provision is informed by the particular terms of the LD provision. The type of LD provision commonly seen in firm LD products, such as the EEI Firm LD Product, obligates the supplier, in the case of interruption for reasons other than force majeure, to make the aggrieved buyer financially whole by reimbursing them for the additional costs, if any, of replacement power. In contrast to this ''make whole'' type of LD provision, other types of LD provisions establish penalties at a fixed-dollar amount, cap penalties at some level, or are otherwise not equivalent to a general ''make whole'' type provision. Under these other types of LD provisions, suppliers only need to compare their savings from interrupting with the specified LD penalty when deciding whether to interrupt power sales. Because such a consideration may not take into account the cost of replacement power, such LD provisions could lead to inefficient supplier interruption and economic harm to the buyer.

1454. We find that a ''make whole'' LD provision, such as that found in the EEI Firm LD Product and in the WSPP Schedule C agreement, does not create incentives that are incompatible with the firmness of the overall product. ''Make whole'' LDs require the seller to consider the price of the replacement power, if it is available, to its original buyer if the seller fails to perform under the contract. There could, of course, be situations where the supplier is still presented with a net financial gain and has an incentive to interrupt, but those incentives would seem to be the same incentives faced by a designated network resource that is a specific generating plant owned by the network customer. In such an instance, the network customer may determine, from time to time, that it is more economic to substitute power from an alternate source in order to allow the originally designated resource to either shut down or to sell its output into the wholesale market. We find no reason to create financial incentives that make purchased power designated as a

[867] *WPPI*, 84 FERC at 61,652.

network resource financially ''more firm'' than owned generation.

1455. Accordingly, we find that the inclusion of a ''make whole'' LD provision in a power purchase agreement does not disqualify that agreement from being designated as a network resource. However, other types of LD provisions may create incentives that are incompatible with the firmness of a power purchase agreement. Thus, as of the effective date of this Final Rule, power purchase agreements designated as network resources may only contain LD provisions that are of the ''make whole'' type. Conversely, power purchase agreements containing LD provisions that provide penalties of a fixed amount, that are capped at a fixed amount, or that otherwise do not require the seller to pay an aggrieved buyer the full cost of replacing interrupted power, are not acceptable. Any contract which contains an unacceptable LD provision, but otherwise qualifies for designation as a network resource and has been properly designated as a network resource prior to the effective date of this Final Rule, will be grandfathered only until the earlier of (1) the expiration of the current term of the power purchase agreement or (2) an indefinite termination [868] of the power purchase agreement as a designated network resource pursuant to section 30.3 of the *pro forma* OATT. In response to the many comments received, we confirm that the LD provisions in both the EEI Firm LD Product and the WSPP Schedule C agreement are acceptable.[869]

1456. Detroit Edison argues that a seller's obligation to pay the cost of replacement power under firm LD contracts is of no value to an LSE that lacks deliverable alternatives. Detroit Edison appears to assume that, as long as an LSE purchasing power had no deliverable alternatives from which to procure power, a designated supplier would not be liable for damages if it chose to interrupt power sales to the buyer for reasons other than force majeure. We disagree. Detroit Edison is addressing the fairly unusual circumstance where a power supply is interrupted, there are no available alternatives in the market, and firm load therefore must be interrupted. We fail to see why this circumstance, and the difficulty of calculating damages for lost load when it occurs, provides a reason why a particular network resource (an LD contract) should not qualify under the *pro forma* OATT as a network resource.

1457. We also disagree with Dynegy's argument that allowing the designation of firm LD products is inconsistent with the existing OATT requirement that a transmission customer own, purchase or have rights to generation. As discussed, firm LD contracts that meet the Commission's requirements for designation do create for the buyer a contractual right to generation and do not contain damage provisions which make the actual incentives under such contracts incompatible with those present in owned generation.

1458. In response to Northwest IOUs' request, we also clarify that the presence or absence of an LD provision does not prevent a transmission provider from using such a resource to serve its bundled native load customers. Rather, as we explain above, it is the type of LD provision that is controlling. A power purchase contract with a ''make whole'' remedy could be used to serve native load customers.

1459. We disagree with Duke and EEI's argument that there is a conflict between the policy guidance given in *Dynegy* (that a power purchase agreement which is interruptible for reasons other than reliability is not eligible for designation as a network resource) and the guidance given in *WPPI* (that a power purchase agreement which permits curtailment to serve the seller's native load is eligible for designation as a network resource). We reiterate the Commission's finding in *WPPI* that a power purchase agreement properly designated as a network resource may permit *curtailment* to serve the seller's native load. Consistent with the long-standing definition in Order No. 888, ''curtailment'' contemplates a reduction in service as a result of system reliability conditions, not economic reasons.

1460. Although we find that the LD provision contained in the WSPP Schedule C agreement does not impair the firmness of that agreement, we note that the agreement otherwise allows interruptions in generation service ''to meet [the] Seller's public utility or statutory obligations to its customers.'' Thus, the WSPP Schedule C agreement appears to allow interruptions for reasons other than reliability and, as a result, would not be eligible for designation as a network resource under the *Dynegy* or *WPPI* precedent. We find that the provision in the WSPP Schedule C agreement allowing for interruption of generation service in order to serve native load would need to be revised to explicitly prohibit interruptions for reasons other than reliability of service to native load in order for that provision to meet the requirements established under *Dynegy* and *WPPI*.

1461. Maintaining the standard for eligibility established in *Dynegy* and *WPPI* will further the Commission's goals of preventing undue discrimination, promoting comparable treatment of customers, and increasing the accuracy of ATC calculations. However, we acknowledge that some may currently be relying on the WSPP Schedule C agreement in designating network resources and that there may be disruption if we were to invalidate the designations of the existing WSPP Schedule C resources. Thus, we exercise our discretion not to invalidate existing designations of the WSPP Schedule C agreements as a result of noncompliance with this particular requirement until the earlier of the following: (1) The expiration of the current term of a power purchase agreement or (2) redesignation of a previously designated WSPP Schedule C resource following a period of temporary or indefinite termination pursuant to sections 30.2 and 30.3 of the *pro forma* OATT. Alternatively, parties may voluntarily reform the offending contract terms in order to preserve their eligibility for network service.

(2) Off-System Resources

Comments

1462. Many commenters request clarification or reconsideration of the information that is required to be specified in section 29.2(v) of the *pro forma* OATT in order to designate a seller's choice contract or system sale as a network resource. Northwest Parties agree with the proposal in the NOPR that system sales may be designated by providing the control area from which the sale is made, transmission arrangements, and delivery points to the transmission provider's transmission system.[870] For system sales, Northwest

[868] As discussed below, in section V.D.6.c, termination of network resource status may either be temporary or indefinite. A firm LD contract that does not have a ''make whole'' LD provision and which is grandfathered here may continue to be temporarily terminated in order to make third-party sales without jeopardizing its eligibility to be redesignated after a third-party sale. However, once a network resource is indefinitely terminated, it must comport with the requirements for LD provisions, and all other requirements for designation of network resources, before it can be redesignated.

[869] As discussed below, however, we otherwise find that the WSPP Schedule C agreement does not comply with the requirements for designation as a network resource because it allows for interruption for reasons other than reliability. We therefore do not need to address requests to clarify that both the buying and selling party to a WSPP Schedule C contract can designate network resources associated with the contract.

[870] Northwest Parties request similar clarification for designation of purchase contracts from one or more specified, individual resources.

Parties argue that unit-specific information is not needed because such sales are, by definition, from a variety of resources and, in any event, the resource-specific information is typically not available to the purchaser. This is particularly true, they argue, for sales from large hydroelectric systems, which are operated as one interconnected unit. For purchase contracts, they argue that unit-specific information is not needed because it is provided in the generation interconnection agreement to the control area where the resource is located. Northwest Parties contend that not requiring unit-specific information for purchase of power, including purchases of system power, is consistent with the Commission's description in the NOPR of the requirements to designate a network resource.

1463. Pinnacle argues that the Final Rule should recognize that the level of detail required by section 29.2(v) may vary depending on circumstances and permit the transmission provider to determine the level of information necessary for the evaluation of the network resource. In some cases, a power purchase agreement may, they argue, appropriately refer to more general information than a specific single control area or single source of supply.

1464. In cases where a power purchase agreement is being sourced by generating units from an external control area, Entergy contends on reply that simply identifying the control area is sufficient for purposes of studying the deliverability of that resource. However, in cases where the power is sourced by generating units internal to the transmission provider's control area, Entergy argues that identifying only the control area does not provide sufficient information to study deliverability. In that case, Entergy argues that the customer must provide the specific information required by section 29.2(v) of the *pro forma* OATT, including the location of the specific generating units. If such information is not available at the time of the network resource designation, Entergy argues that the customer should still be able to designate the agreement as a network resource, but that the customer would have to confirm resource deliverability prior to actually scheduling the service.

1465. TDU Systems argue in their reply comments that specifying the control area and the interface over which power will enter the transmission provider's transmission system from a designated network resource in an external control area is sufficient for purposes of studying the deliverability of that resource. TDU Systems also argue that, for competitive reasons, an LSE should never be required to identify the generator or the transmission zone where the generator is located.

1466. In contrast, EEI requests that the Commission modify section 29.2(v) to clearly state that the transmission provider has the discretion to require the network customer to identify the location of the generator with more specificity than simply specifying the control area in which the network resource is located, since the location will affect the flowgate over which the energy will be transmitted. EEI argues that it is necessary to narrow the location of the source of a power purchase to the system of a particular transmission owner, rather than a control area. PNM-TNMP and Duke also support requirements that network customers provide more information concerning the location of off-system network resources and purchase agreements so that the transmission provider can properly evaluate the impact on its system. Duke states that Duke Carolinas are now receiving requests to designate as network resources power purchase agreements that list the point of delivery as ''the PJM control area'' or ''into Southern.''

1467. Dynegy argues in its reply comments that the Commission has never explained how a transmission customer designating a firm LD contract as a network resource could ever comply with section 29.2 of the *pro forma* OATT, which requires specific information about the generation resource being designated. Dynegy contends that, just like a seller's choice contract, a customer is not entitled to any information about particular generating assets when entering a firm LD purchase contract such as the EEI Firm LD Product. As a result, Dynegy states that it is unclear how a network customer would ever be able to legitimately designate such contracts as a network resource.

1468. In order to help ensure that all network resources are in fact backed by capacity, Dynegy argues that the Commission should require identification of more than just the control area when designating a network resource. Dynegy argues that the Commission should require the generation owner or trading agent for the generation to positively verify that capacity was sold to the entity designating that particular generator as a network resource, and that the designation is appropriate pursuant to the parties' agreement, as is currently required in PJM.

1469. Because some regions of the country determine ATC using a flow-based methodology and other regions use a rated path methodology, EEI argues that section 29.2(v) should be modified to permit transmission providers to require a network customer to designate the point to which the energy is delivered and from which the transmission provider will provide network service if it is not delivered at the generator bus.

1470. Duke requests that the Commission resolve an inconsistency between the NOPR's statement at P 408 that ''when a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate,'' and the statement in the very next sentence that a ''power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) cannot be designated as a network resource.'' Duke notes that significantly more information is required by section 29.2(v) (unit size, VAR capability, operating restrictions, variable generating cost for redispatch computations, *etc.*) than the ''control area from which the power will originate.''

1471. Morgan Stanley contends that the information required in section 29.2(v) must not disallow designation of seller's choice contracts as network resources. They assert that transmission providers use security constrained economic dispatch under which the source of supply in a contract is generally irrelevant from a planning or operational perspective and is therefore not needed. Morgan Stanley also argues that, if the underlying network customer's contract permits the seller to curtail its dispatch and substitute a source from the market, the transmission provider would never actually know the location where a network customer's power is coming from and, thus, it is unclear why the specification of that source should be a requirement. Therefore, Morgan Stanley requests that the Commission consider revising 29.2(v) to eliminate the inclusion of information that is not necessary or make the provision of such information required ''to the extent practicable.''

1472. Duke replies that Morgan Stanley accurately portrays what typically happens under seller's choice contracts, but reaches the wrong conclusion about a remedy. Duke argues that, if network customers are permitted

to designate as network resources contracts that may be relatively long-term, but under which the seller has no obligation to identify the source of the power any sooner than on a day-ahead basis, then ATC may be reserved even though there is no intent to use it. Duke also argues that allowing seller's choice contracts would hamper the transmission provider's ability to plan its system. In Duke's view, it would be appropriate to permit a seller's choice contract to be a designated network resource at the time transmission service is granted for the period such transmission service lasts, as at that point the customer will have designated a source and sink.

1473. Fayetteville recognizes that there are problems related to modeling and reliability in contracts for energy which do not specify particular units as sources, but argues that these problems are exactly the same as those that exist within any vertically integrated utility which names its generation fleet as network resources for its native load.

Commission Determination

1474. Many comments were received with respect to seller's choice and system purchases. Some comments refer not only to seller's choice and system purchases, but also to other possible off-system transactions, including sourcing from owned generation located off-system. We therefore use the term ''off-system resources'' here to refer to all such resources.

1475. The existing requirements in section 29.2(v) are intended to ensure that the network customer designating resources on other transmission systems provides sufficient information to allow the local transmission provider to determine the effect on ATC. Conversely, network customers should not be permitted to designate off-system resources which are so vaguely defined that the effects on ATC cannot be determined. In light of the requests that the Commission clarify exactly what information must be provided in order to designate network resources located off-system, and what information required by section 29.2(v) must be posted on OASIS, we will revise section 29.2(v) of the *pro forma* OATT to specify exactly what information is required.

1476. As revised by the Final Rule, section 29.2(v) of the *pro forma* OATT will require the following information to be provided with the request and posted on OASIS when designating an off-system resource: (1) Identification of the resource as an off-system resource; (2) amount of power to which the customer has rights; (3) identification of the control area(s) from which the power will originate; (4) delivery point(s) to the transmission provider's transmission system; and (5) transmission arrangements on the external transmission system(s). Additionally, section 29.2(v) is revised to require that the following information be provided with such designation, but such information must be masked on OASIS to prevent the release of commercially sensitive information including (1) any operating restrictions (periods of restricted operation, maintenance schedules, minimum loading level of resource, normal operating level of resource); and, (2) approximate variable generating cost ($/MWH) for redispatch computations. Requests to designate off-system network resources submitted on or after the effective date of this Final Rule must include all of the information listed above.

1477. We direct transmission providers to develop OASIS functionality to (1) allow all of the information required for a request to designate network resources to be provided electronically, (2) mask information about operating restrictions and generating cost on OASIS, and (3) allow for queries of all information provided with designation requests in accordance with section 37.6 of the Commission's regulations.[871] As provided in paragraph 385, we also direct transmission providers to work in conjunction with NAESB to develop business practice standards describing procedural requirements for submitting designations over any new OASIS functionality. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. Prior to implementation of this new OASIS functionality, any information that cannot be provided electronically may be submitted by transmitting the information to the transmission provider by telefax or providing the information by telephone over the transmission provider's time recorded telephone line.

1478. Duke argues that there is an inconsistency between the following statements in P 408 of the NOPR: (1) ''when a network customer is designating a system purchase as a new network resource, the source information required in section 29.2(v) should identify that the resource is a system purchase and should identify the control area from which the power will originate''; and (2) the statement in the very next sentence that a ''power purchase agreement that is structured so that a network customer cannot specify all of the information required by section 29.2(v) cannot be designated as a network resource.'' We disagree. The first statement only provided guidance on what could be provided in lieu of the *source of supply* information (as required in the last bullet of section 29.2(v) of the existing *pro forma* OATT) and was not intended to excuse customers from providing all of the relevant information for an off-system purchase other than the specific source of supply. However, the revisions to section 29.2(v) we adopt in this Final Rule remove any confusion.

1479. We disagree with Dynegy's argument that no firm LD contracts would be able to meet the requirements for designation. We note that all of the information required for off-system resources should be available for a seller's choice contract. Even firm LD contracts have variable generating costs (energy cost) and may have maintenance and other operating constraints. If no such constraints are contractually specified, or if no such constraints are relevant to an owned generation resource being designated, then that should be reflected in the information posted on OASIS.

1480. We reject Dynegy's request that the Commission require additional verification by sellers that capacity was in fact sold to an entity designating that particular generator as a network resource and that the network resource designation is appropriate pursuant to the parties' agreement. As the Commission explained in *Illinois Power*,[872] a firm energy purchase need not be backed by capacity to qualify as a designated network resource.

1481. We disagree with commenters who argue that more specific information than the control area must be provided with each request to designate system purchases or seller's choice contracts as network resources. In particular, we disagree with EEI's and Duke's argument that customers designating seller's choice contracts as network resources must be required, on a generic basis, to identify the specific transmission system, rather than the more general control area, in which the physical resources are located. EEI argues that such specificity is required for transmission providers to identify the individual flowgates over which the power will flow into their system. The existing section 29.2(v) of the *pro forma* OATT requires that customers designating network resources identify

[871] 18 CFR 37.6.

[872] 102 FERC ¶ 61,257 at P 14.

the ''delivery point(s) to the transmission provider's transmission system.'' We agree with Entergy and TDU Systems that providing both the control area in which off-system resources are located as well as the delivery point(s) to the transmission provider's transmission system is usually sufficiently specific to allow a transaction to be evaluated for its effect on the ATC of the local transmission system. However, we acknowledge Duke's concern about receiving requests to designate as network resources purchase agreements that list the point of delivery as only vague statements such as ''the PJM control area'' or ''into Southern.'' If any transmission provider believes that it faces unique circumstances that require deviations from the *pro forma* OATT in order to allow them to determine the effects of designations of network resources on ATC, it can, in a filing pursuant to FPA section 205, propose terms and conditions that it demonstrates are consistent with or superior to the *pro forma* OATT.

1482. Because some regions of the country determine ATC using a flow-based methodology and other regions use a rated path methodology, EEI argues that section 29.2(v) should be modified to permit transmission providers to require a network customer to designate the point to which the energy is delivered and from which the transmission provider will provide network service if it is not delivered at the generator bus. It is unclear what specific changes EEI is requesting. We note that, with respect to off-system purchases, section 29.2(v) of the *pro forma* OATT already requires that the delivery point(s) to the transmission provider's transmission system be included in the description of the network resource.

1483. In response to Entergy's request, we clarify that a customer may not designate as a network resource a seller's choice power purchase agreement which is sourced by generating units internal to the transmission provider's control area, since evaluating the effect on ATC would be problematic. We disagree with Entergy that a customer should be able to designate such a resource, even without specifying the location of the specific generating units, provided that the customer's network service from those units is contingent upon confirming resource deliverability prior to actually scheduling the service, because such a policy would still significantly obscure the evaluation of ATC. If a customer wishes to have a choice of resources that are internal to the particular transmission provider's control area from which to dispatch power, it must designate each of the resources as network resources.

1484. We disagree with Morgan Stanley's unsupported comments that the source of supply in a contract is irrelevant. We find that location of resources is a critical factor to the transmission provider's ATC calculations and its ability to model and evaluate the proposed network resource, regardless of whether the transmission providers use security constrained economic dispatch.

(3) Ability To Serve Native Load

Comments

1485. Many parties contend that the Commission's policy with regard to the qualification of network resources affects their ability to serve native load. EEI argues that energy purchases are an integral part of the resources many utilities use to serve their loads, yet often such projected energy purchases are not under contract until shortly before the power is needed. According to EEI, the requirement that a purchase contract be executed to qualify as a network resource jeopardizes the ability of such utilities to serve their native loads because they will not be able to reserve transmission capacity and other users may receive all of the ATC before their contracts are executed.

1486. APPA, EEI and Nevada Companies argue that restrictions on the types of generation and power supply arrangements that qualify for network service may violate section 217 of the FPA. EEI notes that section 217 provides that LSEs are entitled to use firm transmission rights to deliver the output of their generators or purchased energy to meet their service obligations to their loads. In EEI's view, section 217 requires the Commission to exercise its authority in a manner that enables LSEs to secure firm transmission rights on a long term basis for long term power supply arrangements made, or 'planned,' to meet such needs and, therefore, a requirement that network customers and transmission providers not reserve transmission capacity to serve their network loads and native loads unless they either own generation or have executed contracts that specify the source of the energy is inconsistent with section 217. APPA notes that section 217 does not distinguish among the types of power supply arrangements that an LSE must enter into to be protected and that section 217(b)(1)(A) refers to a broad universe of owned or contracted generation that would suffice, so long as the power supplies are for the purpose of meeting a service obligation.

1487. Newmont Mining disagrees that the Commission's requirements for designation of network resources are contrary to the new FPA section 217(b)(2). Newmont Mining argues the legislative history of section 217(b)(2) shows that it was intended essentially to codify Order No. 888 [873] and that the resource designation requirements do not deny LSEs any right to use their transmission, but rather prescribe how they are to implement that right.

1488. EEI, Nevada Companies, PNM-TNMP and South Carolina E&G on reply also argue that the Commission's requirements for eligibility for designation as a network resource may impermissibly conflict with state-mandated procurement plans. EEI and South Carolina E&G contend that, by imposing restrictions on the ability of LSEs to serve their native load, the Commission is indirectly asserting jurisdiction over state-regulated procurement practices, which they further argue is prohibited under *Northern States Power Co.* v. *FERC.*[874]

1489. Nevada Companies argue that the type of contracts that the Commission has determined to be eligible for qualification as network resources tend to be the most expensive. They point out that state regulatory agencies might determine that other types of contracts are more cost-effective without unnecessarily jeopardizing reliability. Even more troubling, they argue, is the problem created when transmission providers have peak loads that can more effectively be served by purchasing power on a short-term period (*i.e.*, less than one year). To reserve the transmission required to serve a needle peak that can occur anytime within a four month period would require the purchase of thousands of megawatt hours of power that Nevada Power knows it will not need, resulting in a disallowance by the Public Utility Commission of Nevada, which approves all open positions, options and hedges for Nevada Power.

1490. Nevada Companies contend that the network designation process should not be changed on systems where the process works reasonably well,

[873] In its reply comments, Newmont Mining cites (through reference to its own NOI reply comments) the statement in H.R. Rep No. 108–65 at 171 (2003) that ''[t]his section is intended to be consistent with the Commission's Order No. 888,'' as well as the statement in S. Rep. No. 109–78 at 50 (2005) that section 217 ''does not affect the Commission's authority under sections 205 and 206 [of the FPA] to ensure that rates are just and reasonable and not unduly discriminatory or preferential.''

[874] 176 F.3d 1090, 1096 (8th Cir. 1999), *cert. denied*, 528 U.S. 1182 (2000).

particularly on systems where transmission providers are required to make significant purchases of power to meet their retail loads. Nevada Companies argue that the Commission should therefore give transmission providers the option of instituting a reservation-based contract demand service similar to that previously approved in *Florida Power*.[875]

1491. Newmont Mining replies that Nevada Companies proposal is not similar to the Florida Power proposal or other approved contract demand network service arrangements, as those services were offered at the request of a network customer; designed to deal with a particular circumstance of the network customer; and offered as an option to, not as a replacement for, standard network integration services. Utah Municipals in their reply comments agree that utilities should not be permitted to unilaterally impose a contract demand ''reservation based'' methodology on its network customers.

1492. Newmont Mining argues that Nevada Companies' request to maintain an open position for a portion of their resource portfolio, in accordance with their required resource planning process, does have some basis, but that Nevada Companies' proposal is not the right solution. If the Commission is inclined to provide some relief to Nevada Companies, Newmont Mining argues that such relief should come, if at all, only after an investigation of how similar problems are handled on other systems and that such relief should be limited. The limitations Newmont Mining suggests include, among other things, excusing Nevada Companies from the requirement, if at all, only to the extent that a specific open portfolio position is contained in a resource plan approved in accordance with applicable law; requiring that the reservation be posted on OASIS; not granting a reservation to Nevada Companies over a competing application for network service by a potential network customer that actually has a designated network resource; and permitting other network customers to hold similar open positions.

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1493. We generally disagree with arguments that the Commission's restrictions on the designation of network resources may violate section 217 of the FPA. Congress did not require that LSEs be able to take transmission service without limitations of any kind in order to serve their native load, and nothing in section 217 suggests that LSEs should not be required to comply with reasonable requirements that are necessary to prevent undue discrimination and maintain a reliable transmission system. The conditions that have been established for taking network transmission service are reasonable and support these goals, and we therefore disagree that such conditions are inconsistent with the requirements of section 217. Furthermore, as Newmont Mining points out, the legislative history of section 217(b)(2) supports the interpretation that section 217 was intended to be consistent with the Commission's authority under sections 205 and 206 of the FPA to ensure that rates are just and reasonable and not unduly discriminatory or preferential, under which the designation requirements in Order No. 888 were adopted.

1494. We also disagree with commenter arguments that the Commission's requirements for eligibility for designation as a network resource impermissibly conflicts with state-mandated procurement plans. We point out that, with the exception of some clarifications on the types of LD provisions that are acceptable in designated firm LD products and what information a customer designating a system purchase or a seller's choice contract must provide, the requirements for designation of network resources are not new. Order No. 888 has long required that contracts be executed and imposed reasonable restrictions on the types of resources that may be designated as network resources.

1495. To the extent that individual transmission providers have unique circumstances or needs that justify a variation from the *pro forma* OATT, those parties can request such a variation and explain why their proposed variation is consistent with or superior to the requirements of the *pro forma* OATT in a section 205 filing. In particular, Nevada Companies' request for approval of a contract demand service in order to address certain issues presented by their unique situation would properly be made in the context of a section 205 filing requesting a deviation from the *pro forma* OATT. We agree with Newmont Mining and Utah Municipals that approved variations, if any, must be applied on a comparable basis to both the transmission provider's merchant function and the other network customers.

(4) General

Comments

1496. A number of commenters raised other general concerns regarding the designation of network resources. TAPS requests that the Commission clarify that conditional firm transmission service is sufficiently firm to meet the requirement that third-party transmission arrangements to deliver a designated purchase to the network be noninterruptible. TAPS also requests that the Commission provide for designation of network resources within the control area on a conditional firm basis.

1497. In its reply comments, South Carolina E&G request clarification of the content and process of making information postings in accordance with section 29.2 of the *pro forma* OATT. South Carolina E&G argues that, taken literally, section 29.2 requires that everything in an application for network service be posted. South Carolina E&G contends, however, that the contents of an application do not fit on OASIS as currently configured, and that making such information available on OASIS is not necessary for the Commission's purposes, particularly given the Commission's representations in favor of preserving the integrity of customer confidential information. South Carolina E&G suggests the Commission require only the following information to be posted on OASIS: identification of the service type as ''network''; identification of the source by name of the generator or system; identification of the sink by name of the network customer's load; identification of the point of receipt by specification of the interface at which the network customer intends to deliver to the resource into the transmission provider's transmission area; and identification of the point of delivery and sink.

1498. South Carolina E&G also requests clarification on how designated network resources are to be posted. South Carolina E&G asks, for instance, whether the Commission expects transmission providers to develop an OASIS template that network customers can update, as necessary, for network resources to simply be posted in PDF format, or be accomplished via the comment section of an OASIS reservation. South Carolina E&G argues that posting via the comment section of OASIS allows for operational ease, but provides limited transparency and includes administrative challenges due to character limitations and formatting constraints. Alternatively, South Carolina E&G argues, new functionality on OASIS that allows customers to post,

[875] *Florida Power Corp*, 81 FERC ¶ 61,247 (1997) (*Florida Power*).

modify and update network resources would satisfy the Commission's requirements, but would involve added costs and time.

1499. TranServ seeks clarification as to the minimum term, if any, that the transmission provider must honor for designation of new network resources. TranServ requests that network resources be allowed to be designated for the same minimum time periods used for firm point-to-point service, *i.e.*, daily or hourly service. Conversely, South Carolina E&G argues in its reply comments that requiring transmission providers to update their list of designated network resources on an hourly basis is too burdensome. South Carolina E&G requests that the Commission allow alternative methods of designating network resources on a short-term basis, such as adding comments to the appropriate comment field on either eTags or OASIS reservations.

1500. TDU Systems argue that the designation of network resources (explicit or implicit) by some transmission providers is automatic, while network customers are required to pay for elaborate studies of every conceivable path affected by the addition of the resource. TDU Systems request that the Commission clarify that the process of network resource designation should be the same for all network users.

1501. APPA, Fayetteville, NCPA, Northwest Parties, TAPS, and Wolverine request that clarifications made to the Commission's policy for qualification as a network resource apply prospectively and/or that sufficient time be allowed after the adoption of the Final Rule such that the necessary products, information systems and business practices can be developed. Such commenters contend that the designated network resources they currently rely upon were acquired and designated consistent with prior Commission precedent, so that changes to the network resource criteria established in this proceeding should not invalidate the continued use of such resources. Because there may be many existing designated network resources that do not meet the standards that the Commission eventually sets, Duke suggests on reply that the Commission may need to permit existing contractual designated network resources that do not qualify under the new standard to retain their designated status until the earlier of the expiration data of the transaction or the expiration date of any necessary transmission service supporting that network resource.

1502. In its reply comments, Dynegy disagrees with request to grandfather existing designated network resources, and argues that the Commission's holding in *Dynegy* was erroneous and should be remedied in its entirety, without the creation of yet another class of grandfathered entities.

Commission Determination

1503. The Commission agrees with TAPS that firm point-to-point transmission service provided on a conditional firm basis is sufficiently firm to be used for transmission to import a designated network resource. Firm point-to-point transmission service provided on a conditional firm basis meets the existing requirement that transmission arrangements in other control areas delivering power purchases designated as network resources to the network customer's transmission provider must not be interruptible for economic reasons, as explained further in section III.F of this Final Rule. With respect to TAPS' second request for clarification to allow for designation of network resources within the control area on a conditional-firm basis, we note that such designation of network resources within the control area will not be allowed, as discussed further in section III.F.

1504. In response to South Carolina E&G's request, we reiterate that not all of the information required by section 29.2 of the *pro forma* OATT for designation of a network resource will be made publicly available on OASIS. As discussed above, information about operating restrictions and generating cost will be masked to protect commercially sensitive information. South Carolina E&G has also requested clarification of the Commission's intent with respect to how designated network resource information is posted. Our existing regulations specify the view, download, and query requirements for information posted regarding network resource designations.[876] The details of how those informational postings are accomplished are best left to be determined as part of the NAESB standards development process.

1505. TranServ requests that the Commission clarify the minimum term, if any, that a transmission provider must honor for designations of new network resources. We agree with TranServ that the minimum term should be the same as the minimum time period used for firm point-to-point service (*i.e.*, daily), unless otherwise demonstrated by the transmission provider and approved by the Commission.[877]

1506. In response to TDU Systems' request for clarification that the process of network resource designation should be the same for all users, we note that section 28.2 of the *pro forma* OATT already provides that ''[t]he Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff.'' We encourage parties to utilize the Commission's Enforcement Hotline to report suspected abused of this process.

b. Documentation for Network Resources

NOPR Proposal

1507. In the NOPR, the Commission noted that transmission providers are responsible for verifying that the network customer has provided all the information required in section 29.2, but that transmission providers are not responsible for verifying that the generating units and power purchase agreements network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. However, the Commission also explained that the transmission provider continues to have the responsibility to verify that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm.

1508. The Commission proposed to require the transmission provider's merchant function as well as network customers to include a statement with each application for network service or to designate a new network resource that attests that, for each network resource identified in the application for service, (1) the transmission customer owns or has committed to purchase the designated network resource, and (2) the designated network resource comports with the requirements for designated network resources.

1509. If the network customer does not include an attestation when it confirms its request, the Commission proposed that the transmission provider will notify the network customer within 15 days of confirmation that its request is deficient and that, wherever possible, the transmission provider will attempt to remedy deficiencies in the request through informal communications with the network customer. If such efforts are unsuccessful, the Commission further

[876] *See* 18 CFR 37.6(a).

[877] *See, e.g., Entergy Services, Inc.*, 105 FERC ¶ 61,318 (2003), *reh'g denied in relevant part*, 109 FERC ¶ 61,216 (2004).

proposed that the status of the request on OASIS will be changed to ''retracted'' and the network customer's request will be terminated without prejudice to the network customer submitting a new request that includes the required attestation, after which the network customer will be assigned a new priority consistent with the date of the new request.

1510. In the event that the transmission provider or any network customer designates a network resource that it does not own or has not committed to purchase, or that does not otherwise comport with the requirements for designated network resources, the Commission proposed that it will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis consistent with the Commission's Policy Statement on Enforcement. The Commission encouraged the transmission provider and other market participants to use the Commission's Enforcement Hotline to report instances when they believe a network customer has designated as a network resource a resource that does not meet the criteria for network resources.

Comments

1511. Several commenters support the overall proposed changes involving attestation requirements, claiming the proposal should help to eliminate abuse, including the practice of some utilities denying transmission requests in order to accommodate its merchant function's plans to engage in future short-term purchases to serve native load.[878] Entegra explicitly supports the Commission's proposal to treat failures to comply as violations of the *pro forma* OATT subject to enforcement. Pinnacle notes that customers should make such attestations in good faith, such that an inadvertent error or omission would not automatically result in recourse to a legal remedy if it can be corrected without adverse impacts.

1512. Dynegy argues in its reply comments that transmission customers who knowingly provide false or inaccurate information in their network resource designations not only jeopardize reliability, but are essentially engaging in theft. Dynegy argues that such parties should be subject to the sanctions and penalties under the Market Behavior Rule,[879] including revocation of the violator's market-based rate authority. APPA and TAPS argue that the new attestation requirements should be consistently applied to all network customers, including the transmission provider's merchant function and affiliates.

1513. Several commenters support the Commission's determination that transmission providers are not required to independently verify the accuracy of an application for network service.[880] Some commenters request that the Commission clarify that transmission providers or transmission owners can voluntarily seek information which verifies that contractual terms meet the requirements in section 30.1 and 30.7 of the *pro forma* OATT.[881] In its reply comments, Duke argues that, without the ability to request the contracts supporting the compliance with the requirement that the designated network resources are firm enough, the Commission may not have authority to require that the network customer support its designation in situations where the network customer is nonjurisdictional.

1514. Pinnacle disagrees with the NOPR proposal that transmission providers should continue to be responsible for verifying the firmness of the network customers' transmission arrangements on other systems. Instead, Pinnacle contends that the transmission customer should have the obligation to ensure that their transmission arrangements meet the requirements needed to ensure that their resources qualify as designated network resources. In its reply comments, Detroit Edison also requests that the Commission require proof that network customers have obtained the requisite transmission service on external systems.

1515. Dynegy, in its reply comments, requests that network resource information and validity of designation be verified not only by the designating customer, but also by the seller or owner of the generation, in order to help ensure that all network resources are in fact backed by capacity. Entegra similarly suggests that the Commission require that entities designating network resources make periodic OASIS postings that will permit verification that the entity designating a generating facility as a network resource actually has rights to power from that facility.

1516. EEI and Entergy allege that the Commission's NOPR attestation proposal may have unintended consequences. Some commenters contend that the gap between the Commission's interpretation of the qualifications of network resources and current procurement practices creates a significant possibility that, if the Commission enforces its policies, it could cause substantial disruptions of service to network and native loads, reduce supply options, or expose network customers and transmission providers to increased liability.[882] EEI asserts that this is because a significant number of network customers and transmission providers are serving their network loads and native loads using resources, particularly power purchase contracts, that may not meet the Commission's requirement for designation as network resources. Some commenters request that the Commission engage in a comprehensive review of power purchase practices before implementing its proposed attestation requirement, and apply any change in policies only to power purchases entered into after the effective date of the Final Rule and after the industry has had time to develop new products that meet the Commission's requirements.[883]

1517. Entegra replies that the expressed concern about the attestation requirement by EEI is puzzling and troubling, because the NOPR did not propose to change the current requirements of the *pro forma* OATT regarding the qualification of network resources. Entegra argues that the widespread non-compliance alleged by EEI makes adoption of an attestation requirement more important and that EEI's allegations may, at most, suggest that the Commission consider some sort of amnesty for network customers and transmission providers willing to self-report and commit to full compliance with the network resource rules going forward.

1518. To ensure that network customers can submit requests for new network service without a final, executed contract, Entergy requests that an attestation to designate a new network resource should not be required until the service request is confirmed. If the request is pre-confirmed, Entergy suggests that the attestation should be provided at the time the request is submitted.

1519. SPP requests that the Commission not require it to police the additional restrictions on the designation of network resources proposed in the NOPR. SPP states that it has neither the data nor the personnel

[878] *E.g.*, Ameren, Entegra, Pinnacle, Public Power Council, and Southern.

[879] *See Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003).

[880] *E.g.*, Ameren, EEI, Suez Energy NA, Nevada Companies, and Utah Municipals.

[881] *E.g.*, Ameren, Duke Reply, Entergy, and Pinnacle.

[882] *E.g.*, EEI, TDU Systems, Indianapolis Power Reply, and South Carolina E&G Reply.

[883] *E.g.*, EEI and Indianapolis Power Reply.

necessary to perform this function and that the Commission should rely on network customer verification, subject to Commission audits. TranServ suggests that the exact nature of how the customer would make the newly required attestation, as well as the treatment of OASIS requests failing to provide the required attestation, should be determined in the NAESB forum at the time when the technical requirements for processing network service requests on OASIS are established.

1520. Several commenters request that the Commission amend section 30.2 of the *pro forma* OATT to require network customers that designate network resources in an external control area also provide a certification from that control area's administrator that the resource being designated is not counted as a designated resource for another load on or off of the system.[884] TDU Systems disagree, arguing on reply that the Commission should not require these types of certifications. TDU Systems recommend, in the alternative, that LSEs on multiple systems should not have to undesignate network resources to serve off-system load, which would eliminate the need for such control area certification for such transactions. TDU Systems also argues that, in the absence of any evidence of abuse, the Commission should not further complicate a process that most market participants would agree is already overly complicated and burdensome.

Commission Determination

1521. The Commission adopts the NOPR proposal that transmission providers continue to be responsible for verifying that third-party transmission arrangements to deliver the purchase to the transmission provider's system are firm, but that transmission providers are not responsible for verifying that the generating units and power purchase agreements network customers designate as network resources satisfy the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. We also adopt the proposal to require both the transmission provider's merchant function and network customers to include a statement with each application for network service or to designate a new network resource that attests, for each network resource identified, that (1) the transmission customer owns or has committed to purchase the designated network resource and (2) the designated network resource comports with the requirements for designated network resources. The network customer should include this attestation in the customer's comment section of the request when it confirms the request on OASIS.

1522. If the network customer does not include the attestation when it confirms the request, the transmission provider must notify the network customer within 15 days of confirmation that its request is deficient, in accordance with the procedures in section 29.2 of the *pro forma* OATT. Whenever possible, the transmission provider shall attempt to remedy deficiencies in the request through informal communications with the network customer. If such efforts are unsuccessful, the transmission provider shall terminate the network customer's request and change the status of the request on OASIS to ''retracted.'' This termination shall be without prejudice to the network customer submitting a new request that includes the required attestation. The network customer shall be assigned a new priority consistent with the date of the new request.

1523. In the event that the transmission provider or any other network customer designates a network resource that it does not own or has not committed to purchase or that does not comport with the requirements for designated network resources, we will deem the network customer to be in violation of the *pro forma* OATT and will consider assessing civil penalties on a case-by-case basis, consistent with the Commission's Policy Statement on Enforcement.[885] We encourage the transmission provider and other market participants to use the Commission's Enforcement Hotline to report instances where they believe a network resource has been designated that does not meet the Commission's requirements.

1524. In response to Pinnacle's request that an inadvertent error or omission should not automatically result in a penalty if it can be corrected without adverse impacts, we reiterate the policy established in the Commission's Policy Statement on Enforcement that enforcement actions will not be imposed ''automatically.'' Enforcement actions are instead considered on a case-by-case basis after consideration of a number of factors which may result in penalties being reduced or eliminated.[886] Among the many factors to be considered pursuant to the Policy Statement on Enforcement is whether the violation is willful.[887] At the same time, consideration is provided for other factors that may weigh for assessing civil penalties, even in circumstances of inadvertent violations. For instance, the Commission considers whether the violator has a history of violations and whether the actions were recklessly or deliberately indifferent to the results.[888] While enforcement actions will not be automatic, and the inadvertence of a violation would be a consideration when determining what, if any, penalty to impose, there may be some instances where inadvertent violations would be found, after consideration as established in the Policy Statement on Enforcement, to warrant a penalty.

1525. Dynegy also requests that transmission customers who knowingly provide false or inaccurate information in their network resource designations be subject to the sanctions and penalties under the Market Behavior Rules,[889] including revocation of the violator's market-based rate authority. We reiterate that violations will be dealt with on a case-by-case basis in accordance with the Policy Statement on Enforcement.

1526. We reject requests to allow the transmission provider to voluntarily seek information which verifies that contractual terms meet the requirements in sections 30.1 and 30.7 of the *pro forma* OATT. Allowing transmission providers to verify terms and conditions of power purchase agreements would put transmission providers in the position of interpreting contracts and accepting or rejecting designations based on their interpretations. We believe such authority is unnecessary in light of the new attestation requirements and that instances of non-compliance are better handled by the Commission's enforcement staff in the context of audits and Enforcement Hotline reports. This applies equally to jurisdictional and nonjurisdictional customers. Every transmission customer must satisfy the requirements of the transmission provider's OATT in order to take service. The Commission thus has authority to require that all network customers support their designations.

1527. We disagree with Pinnacle's argument that transmission providers should not be responsible for verifying the firmness of the network customer's transmission arrangements on other systems. We find that having

[884] *E.g.*, MISO, Indianapolis Power Reply, and Detroit Edison Reply.

[885] *See supra* note 75.

[886] Policy Statement on Enforcement at P 13.

[887] *Id.* at P 20.

[888] *Id.*

[889] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations,* 105 FERC ¶ 61,218 (2003).

transmission providers verify firmness of such transmission arrangements provides a significant benefit to the system and is not unduly burdensome. The confirmation or lack thereof of service on the third-party's system should be readily available on OASIS. If firm third-party service is not confirmed in OASIS, the transmission provider should attempt to remedy any information deficiency in the request through informal communications with the network customer. If such efforts are unsuccessful, the transmission provider should find the request to designate the network resource deficient. Because this information is available on OASIS, we disagree with Detroit Edison's request that the Commission require proof that customers have obtained requisite transmission service on external systems.

1528. We also disagree with SPP's argument that it should not be required to police the additional restrictions on the designation of network resources, since it has neither the data nor the personnel necessary to perform this function. The only ''additional'' restrictions that the transmission provider is called upon to police is that network customers submit the appropriate attestations when requesting designation of a network resource, which places a particularly small burden on the transmission provider. We also do not expect the requirement that transmission providers verify the firmness of the network customer's transmission arrangements on other transmission systems to require any additional data or personnel.

1529. We reject Dynegy's request that the validity of network resource designations be verified not only by the designating customer, but also by the seller or owner of the generation, in order to help ensure that all network resources are in fact backed by capacity. Similarly, we deny Entegra's request that the customer be required to make additional, periodic OASIS postings to demonstrate that it has rights to the power from a designated resource. We find that such additional verifications are unnecessary in light of the new attestation requirements.

1530. With regard to arguments that requiring an attestation may disrupt service, the alleged confusion over the Commission's requirements for designation of network resources seems primarily concerned with whether the EEI Firm LD Product and similar products were eligible to be designated as network resources and whether certain resources can be designated both to serve native load and other network customers. As we have addressed both of these questions above, we believe that many of the concerns about the attestation requirement are resolved. Commenters have not supported claims that the attestation requirement will be either burdensome or that the requirement will require substantial time to comply. As noted above, the minimal additional network resource designation requirements impose in this Final Rule beyond the existing requirements are not expected to be unduly burdensome. While exceptions may be appropriate in cases of legitimate emergencies, we disagree with the implication that a customer should be granted general flexibility to designate a network resource that otherwise may not be eligible.

1531. In response to Entergy's request, we agree that attestations will not be required to be submitted until the service request is confirmed. However, if the request is pre-confirmed, we agree that the attestation must be provided at the time the request is submitted.

1532. In response to TranServ's request that the exact nature of how the customer would make an attestation should be determined in the NAESB forum, we note that the contents and the specific information that is required to be provided with the attestation are specified in the *pro forma* OATT, and we are requiring that the attestation be submitted through OASIS with each request to designate a new network resource. The appropriate subject for transmission providers to coordinate with NAESB to resolve is limited to the appropriate formatting of such information to be provided in OASIS. In response to TranServ's request that NAESB should also determine the treatment of OASIS requests where the customer fails to provide the necessary attestation, we point out that we have already directed that such requests are to be found deficient by the transmission provider and treated in accordance with the procedures in section 29.2 of the *pro forma* OATT.

1533. We reject requests to require network customers designating network resources in an external control area to provide certification from that control area's administrator that the resource being designated is not counted as a designated resource for another load on or off the system. We find that, in absence of any evidence that the Commission's new attestation requirements will be insufficient, this requested verification appears unnecessary.

c. Undesignation of Network Resources

1534. Section 28.2 of the *pro forma* OATT requires the transmission provider, on behalf of its native load customers, to designate resources and loads in the same manner as any network customer under Part III of the *pro forma* OATT (Network Integration Transmission Service). The information provided by the transmission provider must be consistent with the information it uses to calculate ATC. Section 30.3 of the *pro forma* OATT previously allowed the network customer to terminate the designation of all or part of a generating resource as a network resource at any time, but stated that the network customer should provide notification to the transmission provider as soon as reasonably practicable.

1535. In Order No. 888–B, the Commission clarified that the *pro forma* OATT allows network customers to designate network resources over shorter time periods. The Commission indicated that a network customer that seeks to engage in firm sales from its currently designated network resources may terminate the generating resource (or a portion of it) as a network resource pursuant to section 30.3 of the *pro forma* OATT and request that, as set forth in section 29 of the *pro forma* OATT, the same generation resource be designated as a network resource effective with the end of its power sale.[890]

NOPR Proposal

1536. In the NOPR the Commission proposed to continue to allow network customers to ''undesignate'' [891] a portion of their network resources on a short-term basis to make off-system sales. The Commission reiterated that a network customer may redesignate the resource by making a request to designate a new network resource. Additionally, the Commission reiterated that the transmission provider and all network customers must designate their network resources and are prohibited from making firm third-party sales from designated network resources. The Commission stated that, to the extent the transmission provider or a network customer wants to make a firm sale from a network resource, it must undesignate the resource pursuant to section 30.3 of the *pro forma* OATT. The network customer, including the transmission provider itself, could request to redesignate the resource by making a request to designate a new network resource pursuant to section 30.2 of the *pro forma* OATT.

[890] Order No. 888–B at 62,093.

[891] The general term ''undesignation'' refers to both temporary terminations and indefinite terminations of network resource status, as discussed below.

1537. The Commission also sought comment on the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation.

(1) Overview

Comments

1538. Most commenters appear to support the Commission's proposal to continue to allow network customers to undesignate a portion of their network resources on a short-term basis to make off-system sales. However, many commenters request clarification that a temporary undesignation will not cause them to forfeit their rights to transmission priority or ATC for any other time period. Several commenters also request that formal undesignations not be required or that the process not be burdensome. A wide range of comments were received in response to the Commission's request for comments on the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation.

Commission Determination

1539. The Commission generally adopts the NOPR proposal to continue to require network customers and the transmission provider's merchant function to undesignate network resources or portions thereof in order to make certain firm, third-party sales from those resources. In particular, network customers and the transmission provider's merchant function may only enter into a third-party power sale from a designated network resource if the third-party power purchase agreement allows the seller to interrupt power sales to the third party in order to serve the designated network load. Such interruption must be permitted without penalty, to avoid imposing financial incentives that compete with the network resource's obligation to serve its network load.

1540. We clarify that requests to undesignate network resources that are submitted concurrently with a request to redesignate those network resources at a specific point in time shall be considered temporary terminations. Conversely, requests to undesignate network resources submitted without any concurrent request to redesignate those network resources shall be considered a request for indefinite termination of those network resources.

1541. We direct transmission providers to develop OASIS functionality and, working through NAESB, business practice standards describing the procedural requirements for submitting both temporary and indefinite terminations of network resources, to allow network customers to provide all required information for such terminations. Such OASIS functionality should allow for electronic submittal of the type of termination (temporary or indefinite), the effective date and time of the termination, and identification and capacity of resource(s) or portions thereof to be terminated. For temporary terminations, such OASIS functionality should also allow for electronic submittal of (1) effective date and time of redesignation, following the period of temporary termination; (2) information and attestation for redesignating the network resource following the temporary termination, in accordance with section 30.2 of the *pro forma* OATT; and (3) identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination. In response to TranServ's request, we clarify that the request for temporary termination of the resource and the requests for the related transmission service identified in item (3), if any, should be evaluated as a single request, and approved or disapproved as such. We specifically direct transmission providers, working through NAESB, to develop business standards describing the procedures for submitting and processing requests for concomitant evaluations of transmission requests and temporary terminations. When processing such requests, the evaluation of the transmission service requests identified in item (3) should take into account the undesignation of the network resources identified in the request for termination. However, the evaluation of the transmission service requests in item (3) should be processed taking proper account of all competing transmission service requests of higher priority.

1542. Consistent with the requirements for requests for designation of new network resources, the new OASIS functionality should also allow for queries of requests to undesignate and redesignate network resources. In accordance with section 37.6 of the Commission's regulations,[892] such requests must be able to be queried by the publicly available information posted on OASIS.

1543. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. Prior to implementation of this new OASIS functionality, requests for temporary or indefinite terminations of network resources may be submitted by transmitting the required information to the transmission provider by telefax or providing the information by telephone over the transmission provider's time recorded telephone line.

(2) Risk to ATC Rights

Comments

1544. Most commenters request clarification that a temporary undesignation of a network resource does not constitute a forfeiture of priority followed by a new request to designate the network resource, or otherwise put in jeopardy the ATC associated with the designation of that resource for any period other than the period of undesignation.[893] Several commenters argue that virtually no network customers will ever make a firm third-party sale if they are forced to reapply for transmission service after a period of undesignation of their resource, since they would run the risk of losing the ATC associated with the resource.[894] EEI and Entergy contend that the result of such a policy would be that the industry would no longer be able to take advantage of the diversity of peak loads to make firm sales and purchases, and an almost immediate shortage of firm energy sources to serve network and native loads. Duke argues that the approach of not compelling network customers to risk losing the ATC associated with their designated resources beyond the period that the resource is designated would be the comparable approach vis-à-vis point-to-point customers seeking to temporarily redirect their service.

1545. Southern argues that to treat a redesignation as an entirely new application for network resource designation would appear to depart from existing tariff requirements and unnecessarily limit the reliability of network customers' service. It also argues that such an approach would be in contravention with section 217(b)(4) of the FPA, which directs the

[892] 18 CFR 37.6.

[893] *E.g.*, Duke, EEI, Entergy, Exelon, MDEA Reply, Northwest Parties, Pinnacle, Progress Energy, South Carolina E&G Reply, Southern, TDU Systems Reply, TranServ, and WSPP Reply.

[894] *E.g.*, Duke, EEI, Entergy, Progress Energy, South Carolina E&G Reply, and TranServ.

Commission to act in a manner that facilitates the planning and expansion of facilities to meet the reasonable needs of LSEs to satisfy the service obligations of the LSEs. Southern contends that the NOPR proposal would create administrative burdens on transmission providers, potentially treat network service as an inferior product to long term point-to-point transmission service, and introduce a substantial deterrent against optimization of network resources by network customers.

1546. On the other hand, Great Northern initially requests that ATC not be set aside for a former network resource in anticipation that it might be designated as a network resource at some time in the future. In order to ensure comparable treatment for all transmission service customers, Great Northern argues, the Commission should place new requests to designate network resources at the end of the transmission queue, regardless of the prior designation of those resources. Great Northern clarifies on reply that, while ATC should not be set aside for former network resources in anticipation that it might be designated as a network resource at some unspecified time in the future, it has no objection to setting aside ATC to be used by a formerly designated network resource after a temporary, specified period of undesignation such as one month or one season.

1547. NorthWestern, in its reply comments, disagrees with Great Northern's initial comments that new designations be placed at the end of transmission service queue regardless of the prior designation of those resources. NorthWestern argues that such a policy would unduly discriminate against the network customer who is paying for the use of the entire transmission system and grant an undue preference to the point-to-point customer. NorthWestern also argues that the proposal that ATC not be set aside for an undesignated network resource appears to conflict with the Commission's standard interconnection procedures for large and small generators. Once all upgrades specified through the interconnection process have been installed, NorthWestern contends that the generator can be specified as a network resource by any customer, at the time of commercial operation for the generator or at any time in the future.

1548. TAPS appears to support a requirement that transmission customers get back in the queue when re-designating resources, so long as the rules apply to transmission providers as well as network customers.

Commission Determination

1549. In response to the many requests and comments, we clarify that a request for termination of a network resource that is concurrently paired with a request to redesignate that resource at a specific point in time will not result in the network customer permanently forfeiting rights to use that resource as a designated network resource. Any change in ATC that is determined by the transmission provider to have resulted from the temporary termination shall be posted on OASIS during this temporary period. We agree that requiring network customers making temporary terminations to permanently forfeit rights to use this ATC would significantly reduce or eliminate firm third-party power sales. We emphasize, however, that a request to terminate a network resource that is not accompanied with a request to redesignate that resource at a specific point in time is to be considered an indefinite termination. After an indefinite termination of a resource, the network customer has no continuing rights to the use of such resource and future requests to designate that resource would be processed consistent with section 30.2 as a designation of new network resource.

1550. We disagree with NorthWestern's argument that, once upgrades specified through the interconnection process have been installed, the generator can be specified as a network resource by any customer, at the time of commercial operation of the generator or at any time in the future. The Commission has long noted that the generator interconnection process is separate and independent of the acquisition of transmission service for the same generator.[895] The fact that system upgrades may be required to interconnect a generator does not mean any network customer is entitled to the use of that generator at all times, even in the event that the network customer indefinitely terminates the designation of that resource. The integration of network resources with different network customers presents different effects and flows on the transmission system that must be evaluated by the transmission provider.

(3) Minimum Lead-Time

Comments

1551. EEI and Entergy argue that the Commission should not require transmission providers or network customers to undesignate a network resource for a specific amount of time prior to the commencement of an off-system sale. In many instances, EEI argues, short-term firm power sales are made with relatively little lead time, particularly after events such as forced outages or unusual weather conditions. EEI and PNM–TNMP argue that requiring transmission providers or network customers to undesignate a specific amount of time prior to an off-system sale would foreclose the possibility that firm sales could be made with short lead times. That, EEI argues, would adversely affect the sales market, without having any impact on ATC on the path used by the network resource because the network resource would not be undesignated. In EEI's view, imposing lead times on undesignations of network resources would also result in treating network and native load customers less favorably than point-to-point customers. EEI points out that the *pro forma* OATT does not impose any minimum lead times on firm redirects of point-to-point transmission service pursuant to section 22 of the *pro forma* OATT or reassignment of transmission service pursuant to section 23 of the OATT, despite the fact that advance notice of redirects might make the resultant ATC more marketable.

1552. Most commenters, however, appear to support the establishment of a minimum amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation, although they express widely varying opinions on what period of time would be appropriate.

1553. Ameren and Pinnacle contend that the amount of time prior to operation that the transmission provider and other network customers should be required to terminate a network resource should be linked to the frequency of the calculation that gets standardized in the ATC process. Pinnacle contends that, if the undesignation and redesignation are performed on OASIS as they propose, ATC could be recalculated and posted immediately following the undesignation or redesignation. Ameren contends that it cannot comment further until the parameters of the ATC process are defined. FirstEnergy states that the amount of time should be consistent with the time periods required in markets, and that outside of markets, times should be established that coincide with such markets. Southern argues that the current practice, under which a resource is undesignated when

[895] *See, e.g.*, Order No. 2003 at P 118, 744.

it schedules point-to-point transmission service for an off-system sale, provides adequate time to ensure that the appropriate set of network resources is included in the ATC calculation.

1554. PJM notes that, under its system, a generator resource with excess capacity can undesignate the excess resource on a ''day ahead'' basis. PJM believes that this is the proper amount of time needed to ensure resource adequacy. PJM argues that a generator should not, under any circumstance, change the designation of its resource ''same day.''

1555. TranServ argues that, at a minimum, a request for undesignation should be supplied no later than the firm scheduling deadline so that released capacity may be acquired on a non-firm basis. If that data were required to be submitted earlier than the scheduled deadline, TranServ suggests the transmission provider may be able to offer incremental capacity for firm sales. TranServ requests that the Commission establish in the *pro forma* OATT some nominal timeframe for network customers to provide to the transmission provider their planned use of designated resources to serve loads.

1556. Nevada Companies requests that, due to some system emergencies, force majeure events, and hourly scheduling of tie-line changes, they be allowed to change undesignation of network resources at any time to handle these types of events.

Commission Determination

1557. Commenters presented many alternative views in response to the Commission's request in the NOPR for comments on the appropriate minimum lead-time prior to operation that the transmission provider and other network customers should be required to terminate a network resource to ensure that the appropriate set of network resources are included in the ATC calculation. In consideration of these comments, the Commission finds that the appropriate requirement is that network customers not be permitted to make firm third-party sales from any designated network resource without (1) undesignating that resource for the period of the third-party sale pursuant to *pro forma* OATT section 30.3 and (2) providing notice of such undesignation before the firm scheduling deadline (10 a.m. the day before service commences). We find that this requirement strikes the appropriate balance, allowing undesignated capacity to be acquired on a non-firm basis but not creating an undue adverse effect on third-party sales.

1558. We find it unnecessary to incorporate into the *pro forma* OATT provisions relaxed rules for changing the undesignation of network resources at any time to handle system emergencies, force majeure events, forced outages or unusual weather conditions, as suggested by some commenters. Other procedures such as those in NERC's standard for Capacity & Energy Emergencies, EOP–002–2, or the possible use of capacity benefit margin, are more appropriate to deal with legitimate system emergencies. Outside the context of legitimate system emergencies, network customers should rely on appropriate planning and operation, rather than relaxed rules for designation of network resources.

1559. We disagree with EEI's argument that requiring a minimum lead-time will result in treating network and native load customers less favorably than point-to-point customers. In particular, EEI is incorrect in its statement that the OATT does not impose any minimum lead times on firm redirects of point-to-point transmission service or reassignments of transmission service. Firm point-to-point customers are also subject to deadlines for scheduling redirects pursuant to section 22.2 of the *pro forma* OATT. Furthermore, we find that EEI has provided no compelling evidence to support its argument that the adverse impacts on the market for firm energy with short lead times justifies having no minimum lead time.

(4) General

Comments

1560. Several commenters argue that the Commission should not require network customers or the transmission provider to make formal modifications to their designations of network resources when they make firm sales to third parties from those resources.[896] EEI and Southern argue that the practice of most network customers and transmission providers in the ten years since the Commission issued Order No. 888 has been that a network resource is undesignated for any period for which the customer requests firm point-to-point transmission service from the generator or a third party. This practice, EEI argues, has not resulted in any adverse impacts on reliability or on the availability of transmission service and that, to the contrary, selling energy from network resources on a firm basis instead of a non-firm basis frees up firm transmission capacity that otherwise would have to be reserved for the network customer. EEI and NRECA contend that requiring formal undesignations is substantially more cumbersome for network customers and transmission providers making off-system sales.

1561. Progress Energy and TranServ argue that network customers should not have to go through the process of redesignating a network resource as new when the network customer once again needs to use this resource to serve network load. TranServ argues that such a transaction is exactly analogous to a redirect of firm point-to-point service on a firm basis and requests clarification of whether the provider should evaluate a request to undesignate a network resource concomitantly with the assessment of that same customer's point-to-point request, as is done with redirects on a firm basis.

1562. NRECA states that the undesignation requirement is too burdensome and, therefore, the Commission should adopt a comparability requirement that would allow network customers to utilize the practice that many public utility transmission providers use today: *i.e.*, use designated resources for firm off-system transactions or third party uses without having to go through the designation, undesignation and redesignation process. NRECA argues that existing scheduling procedures have allowed transmission providers to deliver power from their designated network resources for off-system merchant purposes reliably and should perform equally well for network customers, provided they still pay a point-to-point charge for the ''outbound'' leg of a delivery to a neighboring network to serve the customer's network load on the neighboring network. NRECA argues in its reply comments that, whatever the Commission decides to do, comparability is the most important principle when considering the undesignation policy and that ''grandfathering'' agreements which would allow transmission providers to essentially get around this requirement would allow undue discrimination to continue. EEI disagrees in its reply comments with NRECA's assertion that transmission providers currently have an advantage over network customers, arguing that the same standards apply to the transmission provider's merchant function and network customers when they seek to make off-system sales from network resources.

1563. PNM–TNMP contends that the Commission has held that formal undesignation and redesignation are not required, so long as the transmission

[896] *E.g.*, EEI, NRECA Reply, PNM–TNMP, and Southern.

provider treats its own resources and the network resources of network customers comparably. PNM–TNMP and Pinnacle further argue that to require formal undesignation and redesignation would appear to do nothing more than impose an extra layer of administration to the management of network resources, making power sales more difficult and potentially reducing financial benefits to end use customers. Bonneville argues that the Commission's proposals regarding the use of network resources for surplus sales are likely to raise the cost to consumers.

1564. Duke requests that the Commission clarify that any product that is not ''designatable'' as a network resource by a buyer may be sold by a seller that happens to be a network customer, without having to undesignate any network resources.

1565. Suez Energy NA requests that the Commission ensure that a utility cannot use redesignation to hoard transmission capacity in order to deprive independent power producers of access to the grid. It contends that a utility could consistently hold transmission to serve generation that never runs for economic reasons and, the day before power flows, redesignate that transmission to accommodate a third-party purchase, effectively using its ability to redesignate network transmission capacity to hoard scarce ATC. In order to prevent potential abuse, Suez Energy NA agrees with the NOPR proposal to require transmission providers to use the same OASIS procedures to designate and terminate network status for themselves that they apply to network customers.

1566. If the Commission requires formal designations and undesignations, EEI asks the Commission to clarify whether it is changing its policy that it is not necessary to modify service agreements in such circumstances in order to avoid requiring transmission providers to make numerous filings amending service agreements.[897] If formal undesignations are required, EEI argues on reply that each transmission provider would be required to submit a revised application for network service under section 29.2 of the *pro forma* OATT both at the time the resource was undesignated and at the time that resource was redesignated. EEI also argues that formal undesignation would require the execution and filing of revised network service agreements reflecting the changes.

1567. South Carolina E&G argues in its reply comments that off-system sales of firm power are typically in the form of a slice-of-system sale. South Carolina E&G requests that the Commission provide guidance for how to treat such a sale of power, suggesting that the transmission provider be permitted to undesignate a slice of a system sufficient to support the firm power sale and then, at the conclusion of the sale, redesignate that slice of the system as a network resource.

1568. While generally supporting the Commission's proposal to continue to allow network customers and the transmission provider, with respect to its native load, to undesignate network resources to allow them to make sales to third parties, some commenters seek certain changes, consideration, or clarification by the Commission.[898] EEI, joined by TDU Systems on reply, argue that the Commission should modify its statement that network customers should be permitted to undesignate network resources ''on a short-term basis to make off system sales.'' They argue that nothing in Order No. 888, the Commission's decisions, or the public interest requires that network resources be undesignated only for short-term sales. They further argue that such sales need not be ''off-system.'' Progress Energy argues that the Commission should only allow transmission customers to undesignate network resources to make firm off-system sales for a term which the transmission customer has adequate generation reserves to serve its network load. In its view, the transmission provider also must have the authority to deny the designation or undesignation of the network resources if the transmission provider determines that it needs the network resources to preserve the reliability of its transmission system or to ensure that there is sufficient transmission capability to support the requested changes. NRECA disagrees on reply, arguing that granting transmission providers the authority to deny undesignation requests would give them too much discretion and the perfect opportunity to discriminate.

1569. Progress Energy agrees with the Commission that network service involves the entire transmission provider's system and does not involve a contract path like point-to-point service. It also agrees that the delivery of a network resource once inside the system does not need to be redirected. Progress Energy notes that peaking resources have low capacity factors and, therefore, their transmission reservations are frequently underutilized. They request that network customers be given the ability to optimize their transmission purchases by bringing energy into the host transmission provider's system from other designated network resources in times when they are not using their peaking designated resources.

1570. MDEA, Progress Energy, and Entergy request that, for reliability and economic reasons, network customers be given the flexibility to substitute new designated network resources without abandoning the original transmission queue position of an existing designated network resource.[899] If the Commission does not change its proposal in order to provide network customers with this flexibility, Progress Energy contends that point-to-point service will be a superior service to network service.

1571. Entergy states that it is important for the Commission to recognize that the undesignation of network resources can be used by network customers as a means of allowing merchant generators the opportunity to displace existing resources in serving network and native load. It argues that the Commission should be wary of limiting the ability of a network customer to undesignate network resources, as any such restriction will have broader implications than just the ability of network customers, including the transmission provider's wholesale merchant function, to sell that resource off-system with point-to-point service.

1572. Entergy also requests that the Commission clarify that, while network customers cannot redirect network service, nothing in this prohibition prevents transmission providers from studying requests to designate new network resources as displacements of existing network resources. It argues that preventing network customers from using automated study functions would significantly hinder the ability of these customers to substitute their existing long-term resources with short-term purchases of energy and capacity from merchant generators when it is economical to do so.

1573. TDU Systems argue that network customers (and transmission providers to the extent they serve native load on other systems) should be able to schedule output on a firm basis from

[897] *See Virginia Electric and Power Co.,* 81 FERC ¶ 61,125 at 61,111–12 (1997), *reh'g denied,* 82 FERC ¶ 61,034 (1998).

[898] *E.g.,* EEI, Pinnacle, and Progress Energy.

[899] In its reply comments, MDEA requests that any such flexibility afforded to transmission providers also be available to network customers on a non-discriminatory basis.

network resources on one system to serve their network loads on neighboring systems without having to designate and redesignate network resources among the various transmission providers' control areas. TDU Systems state this would permit LSEs that serve across multiple systems to come closer to replicating the economic dispatch of control area operators, significantly reducing the cost of discharging their service obligations to the customers they serve.

1574. Xcel opposes requiring a transmission customer to undesignate a network resource even in a situation where the resource is used only transiently to provide off-system sales, arguing that such policy would have significant adverse consequences for customers across the country. It points out that it is native load customers that frequently benefit from purchase of economy energy and that, if an undesignation was required to deliver economy energy, most such transactions likely would not occur. Xcel also argues the NOPR concepts relating to designation of network resources and justification of economy energy purchases are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis.

1575. EEI, joined by TDU Systems on reply, requests that the Commission clarify that any changes to the procedures for designating and undesignating network resources apply only to designations made after the Final Rule becomes effective, in order to avoid substantial adverse impacts on the reliability of service to network and native loads. Duke and Pinnacle request that the Commission require NAESB to develop standards that address undesignation and redesignation and allow sufficient time for the NAESB process and for OASIS tools to be developed and approved, prior to the implementation of a new policy. TranServ asks that the undesignation of network resources be supported on OASIS.

Commission Determination

1576. We disagree with commenters arguing that formal undesignations and/or redesignations of resources used to make firm third-party sales should not be required. The undesignation and redesignation requirements exists not only to promote reliability, but also to prevent undue discrimination, promote comparable treatment of customers, and increase the accuracy of ATC calculations. We find that the interest in advancing these policy goals overrides the minimal burden and cost that submitting undesignations and/or redesignations entails. We disagree with Xcel's argument that most economy energy purchases that benefit its native load customers likely will not take place if undesignation of network resources is required prior to firm, third-party sales. First, the requirement to undesignate network resources only applies to firm sales, while typical non-firm economy energy transactions would not require undesignation. Second, undesignating a network resource is not unduly burdensome, consisting only of electronically submitting several items of information, as described above. Therefore, we do not believe that a transaction prevented purely as a result of the requirement to undesignate network resources would have provided any significant economic value had it taken place.

1577. We find that requests to allow ''informal undesignations'' appear to be simply requests to not require undesignations at all. Since the salient feature of requiring an undesignation is that the proper account is taken of the effects on ATC, informal undesignations, which do not take proper account of the fact that a resource is no longer a designated network resource, appear to serve no purpose.

1578. With regard to PNM-TNMP's argument that the Commission has held that formal undesignation and redesignation are not required, so long as the transmission provider treats its own resources and the network customer's resources comparably, we believe PNM-TNMP misunderstands our policies. We note that PNM-TNMP provides no citation to Commission precedent to support its statement.

1579. Duke requests clarification as to whether a network customer must undesignate a network resource in order to make a third-party sale from that resource if the third-party sale would not itself qualify to be designated as a network resource. We reiterate the existing requirement that designated network resources must not be committed for sale to non-designated third-party load or include resources that otherwise cannot be called upon to meet the network customer's network load on a noninterruptible basis. We find that a resource is ''committed for sale to a non-designated third party load'' if a power purchase agreement for the sale from that resource provides for penalties if service to the third party is interrupted in order to serve the designated network load.

1580. In response to comments by EEI, NRECA, and Suez Energy NA, we reiterate that all parties, including transmission providers serving their native loads, are subject to these requirements for designation and undesignation of network resources. Section 28.2 of the *pro forma* OATT clearly provides that transmission providers are required to designate resources and loads in the same manner as any network customer. We encourage parties suspecting that transmission providers or other network customers are not conforming to the requirements for designating or undesignating network resources to report their concerns using the Commission's Enforcement Hotline.

1581. EEI has requested clarification of whether the Commission is changing its policy that transmission providers do not need to modify network service agreements when network resources are undesignated and redesignated. We have not proposed and do not intend to begin requiring that network customers file modified service agreements when network resources are designated or undesignated. As we explained in *Dayton Power and Light Co.*,[900] ''changes in network resources may require the customer to file a request under OASIS, but a change to the information recorded initially in the network service agreement is not a requirement.'' EEI also argues that, if formal undesignations are required, then each transmission provider would be required to submit a revised application for network service under section 29.2 of the *pro forma* OATT, both at the time the resource was undesignated and the time that resource was redesignated. We disagree. There is no requirement that a transmission provider submit a revised application for network service every time a resource is designated or undesignated.

1582. In response to a request by South Carolina E&G, we clarify that firm third-party sales may be made from an undesignated portion of a network customer's network resources (*i.e.*, a ''slice-of-system sale''), so long as all of the applicable requirements are met. In particular, the network customer must submit undesignations for each portion of each resource supporting the third-party sale. If the undesignation is temporary, then the request must be accompanied by a request to redesignate the resource(s) on a specific date. When the undesignation takes effect, the network customer must update the capacities specified in its list of designated network resources posted on OASIS.

1583. We agree with EEI and TDU Systems' comments that there should be

[900] 93 FERC ¶ 61,331 at 62,128 (2000).

no minimum term for undesignations. We also agree with EEI and TDU Systems' arguments that network customers should not be restricted to temporarily undesignating network resources only for use in off-system sales, and clarify that network customers are not so restricted.

1584. We agree with Progress Energy that network customers should only make firm third-party sales when they have sufficient generation reserves to serve their loads. However, the purpose of the *pro forma* OATT is to provide nondiscriminatory transmission access, not to enforce generation adequacy requirements.

1585. With regard to Progress Energy's request for flexibility to evaluate potential impacts to the transmission system related to the undesignation and redesignation of network resources, we find that situations where undesignations cannot be accommodated due to transmission constraints should be extremely rare, such as highly-extraordinary counterflow situations. In such rare situations, the transmission provider should attempt to remedy the situation without denying the undesignation. If it is determined that the resource cannot be undesignated without jeopardizing reliability, then the transmission provider may deny the request for undesignation.

1586. We share NRECA's concern that allowing transmission providers to deny undesignations for reliability reasons could give a direct market competitor a significant opportunity to discriminate, but must weigh this concern against our significant interest in preserving reliability. We point out that transmission providers denying requests for service or changes to service because of reliability concerns must post a description of such denials in accordance with section 37.6(e)(2) of the Commission's regulations.[901] Again, we encourage any parties with concerns about denials of service or changes to service by a transmission provider for reasons of reliability to report their concerns to the Commission's Enforcement Hotline.

1587. We deny requests by MDEA, Progress Energy, and Entergy that network customers be given the flexibility to substitute new designated network resources without abandoning the original transmission queue position of an existing designated network resource. These parties seem to be requesting that a network customer be allowed to be ''first in line'' to use the ATC freed up by an undesignation of a network resource, as long as the network customer uses that ATC to designate an alternate resource. We disagree. Granting this request would, without any apparent justification, put point-to-point customers seeking ATC freed up by an undesignation at a disadvantage. We also disagree that, if the Commission does not allow network customers this flexibility, point-to-point service will be a superior service to network service. Progress Energy seems to be arguing that the point-to-point customer's ability to engage in a redirect affords that customer more flexibility than the network customer. We point out that redirects of point-to-point service on a firm basis are only on an ''as-available'' basis. Firm point-to-point customers cannot redirect unless ATC is available to support such a redirect after all higher-priority requests have been accommodated.

1588. Entergy has requested clarification that, while network customers cannot redirect network service, nothing in this prohibition prevents transmission providers from studying requests to designate new network resources as displacements of existing network resources. Although Entergy's request is unclear, we reiterate that redirects are not allowed within the context of network service and that network customers are not ''first in line'' to use ATC freed up by their undesignation of another network resource. Such requests must be processed taking proper account of all competing transmission service requests of higher priority.

1589. We disagree with TDU System's argument that network customers should be able to schedule output on a firm basis from network resources on one system to serve their network loads on neighboring systems without having to designate and redesignate network resources among the various transmission providers' control areas. Allowing network customers to not formally undesignate and redesignate network resources, even only when using those resources to serve their network loads on neighboring systems, will necessarily result in inaccurate evaluations of ATC. We reiterate that the burden associated with undesignating and redesignating the resources is particularly light and find that requiring network customers to make temporary undesignations when making third-party firm sales is thus justified in light of the ATC-related benefits.

1590. Xcel argues that the concepts relating to designation of network resources are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis. We agree that Day 2 RTOs do not use the physical rights model contemplated under the *pro forma* OATT and, hence, not all the provisions discussed here are directly applicable to Day 2 markets. However, as we explain in section IV.C.2, RTOs and ISOs must make the necessary filings to comply with the Final Rule, or demonstrate that their existing tariff provisions are consistent with or superior to the terms of the revised *pro forma* OATT.

1591. We agree with parties arguing that network customers should not be required to use the new NAESB processes and OASIS tools to be developed in response to this section until such time as the NAESB standards and OASIS functionality have been developed and implemented. However, once the new standards and functionality are in place, network customers must use these new procedures to undesignate (whether temporarily or as part of an indefinite termination) any network resources, regardless of the date that those resources were originally designated.

7. Clarifications Related to Network Service

a. Secondary Network Service

1592. Section 28.4 of the existing *pro forma* OATT allows a network customer to deliver energy to its network load from non-designated network resources on an as-available basis without additional charge, referred to as secondary network service. In Order No. 888, the Commission described such energy as non-firm economy energy purchases used to displace firm network resources.[902]

1593. The use of secondary network service to deliver purchased power when a network customer is making off-system sales has been raised in several Commission investigations and audits. In *Idaho Power*, the Commission accepted a settlement with Idaho Power related to Idaho Power's incorrect use of the native load priority to access its transmission system.[903] In *Idaho Power*, the utility's wholesale merchant function purchased power outside of Idaho Power's control area to facilitate an off-system sale and used secondary network service to bring the purchases into Idaho Power's control area.[904] In accepting the settlement, the Commission stated that ''[i]t is axiomatic that the native load priority

[901] 18 CFR 37.6(e)(2).

[902] Order No. 888 at 31,751.

[903] *Idaho Power Co.*, 103 FERC ¶ 61,182 at P 2 (2003) (*Idaho Power*).

[904] *Id.* at P 4.

cannot be used to complete sales that are not necessary to serve native load.'' [905] In *MidAmerican*, the Commission issued an audit report that contained a finding that MidAmerican's wholesale merchant function used network service instead of point-to-point service to deliver short-term energy purchases to its control area that were not used to serve MidAmerican's native load.[906]

NOPR Proposal

1594. In the NOPR, the Commission proposed to clarify that a network customer may not use secondary network service to import energy onto its system to support an off-system sale if the purchased power does not displace the customer's own higher cost generation. The Commission therefore proposed to modify section 28.4 of the *pro forma* OATT to state that a network customer may use secondary network service only to deliver economy energy and to define ''economy energy'' as energy purchased by a network customer that displaces the customer's own higher cost generation for the purpose of serving the customer's designated network loads. The Commission further explained that all participants engaging in purchases for resale must compete on a comparable basis and use point-to-point service to complete all segments of a purchase for resale off-system.

(1) Overview

Comments

1595. Several commenters agree with the Commission and support the proposed clarification regarding the use of secondary network service.[907] Alberta Intervenors state that such a restriction ensures fair competition among network customers and preserves the entitlement of native load customers.

1596. Other participants oppose the proposal, arguing that it is too broad and would interfere with legitimate activity by network customers.[908] EEI points out that, if a network customer is using all available network resources but is still purchasing energy from non-designated network resources to meet its peak native load, the network customer would need to rely on secondary service to transmit this purchase. In EEI's view, the Commission's proposal would prevent this customer from using secondary service for this non-economy energy, thereby interfering with its service obligations. To avoid such cases, EEI, Pinnacle, and PGP recommend that secondary service not be limited to economy energy only. NRECA states that the Commission's proposed limitation on the use of secondary service would prevent network customers from meeting their native load obligations in cases of extreme weather and power outages. NRECA asks the Commission to state explicitly in section 28.4 of the *pro forma* OATT that secondary service may not be used to facilitate off-system third party sales, but rather must be used to import power needed to serve network load economically and efficiently. Entergy suggests the Commission abandon the limitation and specify simply that secondary service cannot be used to serve loads other than the network or native load.

1597. Others argue that the restriction of secondary service to only economy energy would have unintended consequences regarding the purchase of renewable resources. Emerald, Flathead, and the Northwest Parties state that, for reasons of customer demand or contractual obligation, network customers may be required to purchase renewable power that generally is more expensive than traditional thermal or hydro electric generation. These purchases could displace less expensive non-renewable resources, resulting in the need for the network customer to make off-system sales of the non-renewable resources. Emerald, Flathead, and Northwest Parties suggest that the Commission revise the definition of ''economy energy'' to include an exception for renewable energy. TAPS raises a similar issue, asking the Commission to clarify that economy purchases as well as substitute resources qualify for use of secondary service.

1598. EEI argues that the proposed limitation on secondary service would require all network customers to engage in a specific form of Commission-regulated economic dispatch, while requiring transmission providers to evaluate each resource and become ''dispatch police.'' Entergy, SPP, and PGP agree. They assert that calculating the ''cost'' of power is problematic, inherently subjective and burdensome because transmission providers lack the necessary knowledge to perform this analysis. EEI, Entergy, SPP, and PGP instead suggest that the Commission conduct periodic audits of secondary service to ensure compliance with the requirements of OATT section 28.4 rather than transmission providers.

1599. Although Powerex supports the Commission's restriction on the proper use of secondary service, it also states that determining whether or not an import would qualify as ''economy energy'' would be difficult. Powerex requests that the Commission implement specific rules in advance of such transactions to resolve uncertainty. It suggests a capacity test to prevent preferential acquisition of generation capacity, a tariff prohibition on the use by the network customer or its energy affiliates of any export transmission capacity made available on another intertie, and the modification of business practices governing curtailment. In reply, Alberta Intervenors agree with Powerex's proposed changes to curtailment practices, but disagree with the other two elements. Alberta Intervenors assert that the tariff prohibition causes inefficient use of ATC and that the capacity test is not a stand-alone test and, as a result, would only be helpful as a supplement to the ''economy energy'' test.

1600. Some participants raise other issues not addressed in the NOPR. South Carolina E&G asks that the Commission clarify its policy on purchases of economy energy, as well as provide a clear definition of the acceptable trading practices—notably parking, hubbing, and lending—under the current *pro forma* OATT. Emerald and Flathead request the Commission to revise the definition of ''network load'' in section 1.24 of the *pro forma* OATT to allow point-to-point and network service to the same discrete point of delivery. Morgan Stanley asks that the Commission explain why using secondary service to make an off-system purchase while there is any off-system sale during the same interval is improper and whether the Commission will prohibit such activity only if the off-system purchase and sale are part of a single transaction. Finally, Xcel argues that the concepts relating to designation of network resources are irrelevant in the context of an RTO where energy is procured and dispatched throughout the RTO on a security constrained economic basis.

Commission Determination

1601. In general, the Commission agrees with parties that favor an expansion of the proper use of secondary network service. Although we affirm our finding in *MidAmerican*,[909] the Commission

[905] *Id.*

[906] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005).

[907] *E.g.*, Alberta Intervenors, Southern, Suez Energy NA, and TAPS.

[908] *E.g.*, EEI, Entergy, Northwest Parties, NRECA, Pinnacle, PGP, Southern, and Xcel.

[909] *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 at P 6 (2005) (*MidAmerican*). Following an audit, the Commission found that MidAmerican's

recognizes that there are instances outside the proposed definition of economy energy that warrant the use of secondary service in order to serve network loads reliably. The Commission therefore declines to adopt the definition of economy energy proposed in the NOPR and, instead, will retain the existing section 28.4 that permits use of secondary network service ''to deliver energy to its Network Loads.''

1602. With respect to Powerex's comments, we reject the requested clarifications as Powerex has not fully supported the use of its proposed capacity test or other measures and has not demonstrated that such test would not preclude legitimate uses of this priority as noted in the NOPR. If parties suspect inappropriate use of secondary network service, they may report the suspected activity to the Commission's Enforcement Hotline or file a compliant with the Commission pursuant to FPA section 206. Furthermore, the Commission's staff will continue to provide oversight of all tariff-related activities through its enforcement program.

(2) ''On an as-available basis''

1603. Section 28.4 of the existing *pro forma* OATT allows a network customer to use secondary network service to deliver energy purchases to its network load from non-designated resources ''on an as-available basis.'' However, the current *pro forma* OATT does not specify how a network customer must arrange for secondary network service.

NOPR Proposal

1604. In the NOPR, the Commission proposed to modify section 28.4 of the *pro forma* OATT to clarify that a network customer does not need to file an application for network service to receive secondary service. Instead, the customer must merely request such service on OASIS in a manner consistent with *pro forma* OATT sections 18.1 and 18.2 (Procedures for Arranging Non-Firm Point-to-Point Transmission Service).

Comments

1605. TDU Systems requests that the Commission clarify that time constraints located in OATT section 18.3 are not applicable to secondary service. Section 18.3 provides that requests for non-firm point-to-point service shall not be made before certain specified periods (more than 60 days in advance for monthly service, more than 14 days in advance for weekly service, *etc.*). TDU Systems states that some of its members currently use secondary service to access economy off-system purchases where intervening transmission constraints preclude the designation of those resources as network resources for long periods of time. Application of the non-firm point-to-point service request deadlines would impair TDU Systems' ability to rely on secondary service in those instances since they would extend beyond the timing requirements set forth in section 18.3.

Commission Determination

1606. The Commission clarifies that secondary service must be requested in accordance with section 18, including the timing restrictions set forth in section 18.3, of the *pro forma* OATT. Secondary service is on an as-available basis, and network customers should not be permitted to lock in such service in advance of other non-firm uses of available transmission. Allowing lower-priority secondary service to have a scheduling advantage over non-firm transmission would be inappropriate and would discourage the use of non-firm transmission service, thereby minimizing the revenue credits from non-firm transmission service that benefit all firm transmission customers.

(3) Redirect of Network Service

1607. The current *pro forma* OATT does not include any provision to change the point of receipt for an off-system designated network resource in a manner similar to redirect of point-to-point service. We are aware, however, that several transmission providers have posted business practices that allow network customers either to substitute an off-system non-designated network resource for a designated network resource or to redirect the point of receipt associated with an existing network resource.

NOPR Proposal

1608. The Commission proposed to clarify that network customers may not redirect network service in a manner comparable to redirect of point-to-point service, as network service involves no identified contract path and is, therefore, not a directable service. Should a network customer wish to substitute one designated network resource for another, the Commission stated that it must terminate the existing resource and designate a new one. The Commission explained that the network customer could also request to redesignate its original network resource by making a request to designate a new network resource. Alternatively, a network customer could use secondary network service when it wants to substitute a non-designated network resource for a designated network resource on an as-available basis.

Comments

1609. MISO strongly supports the Commission's clarification stating that network service is not a directable service and believes that the proposal appropriately clarifies the Commission's policy on redirect service. TDU Systems and NRECA, however, believe that the Commission should allow redirects of network service to deliver an LSE's resources. TDU Systems assert that redirect of network service is critical to LSEs serving native load across multiple transmission systems because it allows the amount of flexibility necessary to manage power supply costs. In addition, in TDU Systems' view, redirects have no effect on system reliability.

1610. EEI argues on reply that it is unclear why redirects of network service should be allowed. The advantage of redirecting firm point-to-point service is that the customer does not have to pay an additional charge for transmission service. However, both TDU Systems and NRECA agree that network customers should pay an additional charge for transmission service from network resources to off-system loads.

1611. Sacramento alternatively recommends that the Commission remove the ban on off-system sales in order to maximize efficiency in allocating transmission capacity. Occidental requests that the Commission place all transmission, including on behalf of native load, under the OATT guidelines to ensure that service is provided in a non-discriminatory fashion.

Commission Determination

1612. The Commission clarifies that network customers may not redirect network service in a manner comparable to the way customers redirect point-to-point service. Point-to-point service consists of a contract-path with a designated point of receipt and point of delivery. Network service has no identified contract-path and is therefore not a directable service. Network service instead provides for the integration of new network resources and permits designation of another network resource, which has the same practical effect as redirecting network service. If the customer wants to permanently

wholesale merchant function used network service instead of point-to-point service to deliver short-term energy purchases to its control area that were not used to serve MidAmerican's native load. The Commission stressed that the use of secondary network service is not for the purpose of serving off-system sales. *Id.* at P 6. The modifications to section 28.4 adopted in this Final Rule do not alter that limitation.

substitute one designated network resource for another, it should terminate the designation of the existing network resource and designate a new network resource. The customer could then simply request to redesignate its original network resource, if it so desires, by making a request to designate a new network resource. The ability of a network customer to also temporarily substitute one designated network resource for another is addressed in section V.D.6.

1613. The Commission rejects Sacramento's proposal to remove the ban on off-system sales. Network service is not based upon making off-system sales, but rather on integrating a network customer's resources with its load. Transmission providers must take point-to-point transmission service for off-system sales and network customers should be treated comparably. The Commission also rejects Occidental's request to place all transmission, including on behalf of native load, under the *pro forma* OATT. In Order No. 888–A the Commission clarified that a ''transmission provider is not required to 'take service' under its own tariff for the transmission of power that is purchased on behalf of bundled retail customers.'' [910] However, the Commission required that transmission providers, pursuant to section 28.2 of the *pro forma* OATT, must designate network resources and network loads in the same manner as any network customer. Occidental offers no explanation why the existing requirement of section 28.2 is not sufficient to address its concerns.

b. Behind the Meter Generation

1614. In Order No. 888, in response to customers with load served by ''behind the meter'' generation that sought to eliminate such load from their network calculation, the Commission found that a customer may exclude a particular load at discrete points of delivery from its load ratio share of the allocated cost of the transmission provider's integrated system. The Commission determined, however, that customers electing to do so must seek alternative transmission service, such as point-to-point transmission service, for any load that has not been designated as network load for network service.[911] In Order No. 888–A, the Commission stated that it would permit a network customer to either designate all of a discrete load as network load under the network integration transmission service or to exclude the *entirety* of a discrete load from network service and serve such load with the customer's behind the meter generation and/or through any point-to-point transmission service.[912]

1615. The Commission did not address the subject of behind the meter generation in the NOPR. A few commenters nonetheless proposed revisions to the *pro forma* OATT to require netting of a network customer's behind the meter generation against their network load as described in more detail below.

Comments

1616. Some commenters argue that, in order to meet the objective of eliminating discrimination in the provision of open access transmission service, the Commission must require comparable treatment between retail native load and network customers by allowing network customers to net behind the meter generation against their network load.[913] Specifically, such commenters argue that the Commission should modify the current pricing rules for network service to allow an LSE's load ratio share to reflect the reduction in load caused by behind the meter generation serving retail load.[914] In support of this position, these commenters argue that assigning transmission-related costs to customers that do not rely on the transmission provider's system to serve load is inconsistent with the Commission's cost-causation principles.[915] For example, CAC/EPUC contends that customer generation does not cause the transmission provider to incur costs when power is not being sold to or taken off the grid. Similarly, AMP-Ohio argues that it is inappropriate to assign a full load ratio share of transmission-related costs to behind the meter generation customers that do not use the network to the full extent of their load ratio shares.[916] Further, CAC/EPUC asserts that measuring the customer's use of the transmission system at the customer's meter would be appropriate as it would demonstrate that, if no power flows to the customer from the grid occur, that customer has not used nor caused costs to be incurred by the grid for the delivery of its energy requirements.

1617. Some commenters note that the Commission has approved PJM netting provisions that apply to behind the meter generation used by non-retail and wholesale customers to serve load.[917] These same commenters further observe that PJM has filed with the Commission to expand participation in its behind the meter generation netting program to include municipal, electric cooperatives, and electric distribution transmission customers who take network service on the PJM system pursuant to a settlement agreement filed by PJM on October 24, 2005 in Docket No. EL05–127–000.[918]

1618. Further, both TAPS and AMP-Ohio argue that behind the meter generation provides benefits to the transmission provider that should be taken into account as part of system planning obligations. For instance, AMP-Ohio asserts that utility planning can and should be able to take into account the ability of customers to reduce their load on the system with behind the meter generation. TDU Systems also notes PJM's representation that allowing municipal and electric cooperative system participation in behind the meter generation netting programs increased reliability and demand response opportunities on PJM's system.[919] Similarly, TAPS observes that PJM's rules reserve the right to call upon non-retail behind the meter generation under certain conditions.

Commission Determination

1619. The Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs. Commenters in this proceeding have not provided any different arguments that were not fully considered and addressed in Order No. 888, *et al.* The existing *pro forma* OATT already permits transmission

[910] Order No. 888–A at 30,216.

[911] Order No. 888 at 31,736.

[912] Order No. 888–A at 30,258–61.

[913] *E.g.,* TAPS, TDU Systems, AMP-Ohio, and CAC/EPUC.

[914] TDU Systems and TAPS also cite *Consumers Energy*, 98 FERC ¶ 61,333 at 62,410 (2002) (requiring that a transmission provider's retail load associated with behind the meter generation be included in the transmission provider's load ratio share to ensure comparability between transmission providers and network customers in the calculation of load ratio share).

[915] *E.g.,* AMP-Ohio, CAC/EPUC, and TAPS.

[916] *Citing Occidental Chemical Corporation* v. *PJM Interconnection, L.L.C., and Delmarva Power & Light Company*, 102 FERC ¶ 61,275 at P 14 (2003) (''Access charges for use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost-causation.''); *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113, at P 28 (2004).

[917] *E.g.,* AMP-Ohio, TAPS, and TDU Systems (*citing PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113 (2004), *reh'g denied*, 108 FERC ¶ 61,032 (2004) (*PJM*)).

[918] This settlement agreement was accepted in *PJM Interconnection, L.L.C.*, 113 FERC ¶ 61,279 (2005).

[919] *PJM Interconnection, L.L.C.*, 113 FERC ¶ 63,024 (2005).

customers to exclude the *entirety* of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point transmission service, thereby reducing the network customer's load ratio share. Therefore, the Commission's existing policy already provides customers with the opportunity to reduce network service costs to the extent a customer is not relying on the transmission system to meet its energy needs.[920] As the Commission concluded in Order No. 888–A, transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load.[921] We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters.

8. Transmission Curtailments

1620. In the NOPR, the Commission proposed no changes to the *pro forma* OATT with respect to curtailment provisions for point-to-point service (set forth in sections 13.6 and 14.7) and network service (set forth in section 33). These provisions establish the terms and conditions under which a transmission provider may curtail service to maintain reliable operation of the system. Though several commenters claimed in response to the NOI that the reasons for transmission curtailments are difficult to discern, they did not provide sufficient detail to indicate whether that difficulty is a result of inadequate disclosure regulations, inadequate compliance with those regulations, or some other reason. Therefore, the Commission sought further comment on whether requiring transmission providers to post additional information would improve transparency and the ability of customers to make use of that information. The Commission also declined in the NOPR to propose generic penalties for improper transmission curtailments.

Comments

1621. APPA suggests that the Commission require transmission providers to produce additional information regarding firm transmission service curtailments, including all circumstances and events contributing to the need for such firm service curtailments, specific services and customers curtailed (including the transmission provider's own retail loads), and the duration of all such curtailments. TAPS also urges the Commission to move toward maximum transparency and require that sufficient information be provided for a customer to evaluate whether it has been treated fairly as compared to other users of the system including the transmission provider. TDU Systems suggests that the Commission require investigations into the need for network upgrades when Level 5 Transmission Loading Relief (TLR) procedures are repeatedly employed. It also suggests that all Level 5 TLRs be posted on OASIS and filed with the Commission. EEI agrees that providing customers with information on transmission curtailments may help to reduce confusion and suspicion concerning curtailments and suggests the Commission request WEQ (NAESB) to develop a more detailed template for posting information on curtailments that will be more useful to customers.

1622. Southern and other commenters[922] state that sufficient information regarding curtailments of transmission service is already available on OASIS and believe that the existing rules requiring transmission providers to make curtailment data available on OASIS are adequate. Nevada Companies request the Commission be very specific if it decides to mandate additional reporting requirements in order to remove the burden of potential confidentiality problems from the reporting entity.

1623. Powerex is concerned about inconsistent communication and curtailment procedures. It recommends that the Commission require three additional measures including: Early notice of curtailment through the use of the ''recall'' function on OASIS; a requirement to provide credits for curtailed service when non-firm point-to-point transmission service is interrupted; and requiring *pro rata* curtailments made prior to the energy scheduling and tagging deadline (*e.g.*, 20 minutes before the operating hour) to be based on reservation rather than schedule. In its reply comments, Seattle states support of *pro rata* curtailments based on reservations. TDU Systems recommend that the Commission require transmission providers to refund transmission charges to curtailed customers, to discourage transmission providers from overselling their systems. On reply, EEI and PNM–TNMP urge the Commission to reject the proposals to require transmission providers to refund transmission service charges to curtailed customers. They state that transmission providers are following ATC calculation procedures, but the planning process is not structured to overbuild the system to ensure that no curtailments occur. They also argue that the rate of return permitted in existing cost of service regulation does not account for the risk of loss of curtailment-related revenues. Northwest IOUs request the Commission examine whether *pro rata* curtailments of transactions to relieve transmission constraints unnecessarily impose burdens on transmission customers, because different curtailments on different paths have different effectiveness in relieving a given transmission constraint.

1624. Manitoba Hydro notes that MISO is the only RTO in the Eastern Interconnection that does not redispatch when constraints occur on non-market to market flows. Manitoba Hydro therefore urges the Commission to encourage implementation of redispatch to the fullest extent before resorting to curtailment. Seattle also supports modifying the *pro forma* OATT to require reliability redispatch. Seattle proposes that redispatch costs should be allocated to all classes of customers, and transmission providers' cost recovery should be allowed through automatic adjustment clause-type formulas to ensure all such costs are recovered. It suggests that routine maintenance outages are resulting in curtailments, which is an indication that transmission service is oversold. Seattle further suggests that transmission providers prepare a quarterly incident report for redispatch events detailing circumstances resulting in the redispatch, system status information, power transfer distribution factors, generator offers for redispatch and other information supporting redispatch determinations, including the basis for selecting generators called for redispatch.

1625. APPA, EEI and others comment that the Commission should not impose generic penalties for improper curtailments, but treat violations on a case-by-case basis. To ensure compliance with curtailment posting information, Southwestern Coop suggests that the Commission adopt generic penalties for curtailment violations, claiming that penalties for transmission provider curtailment discrimination would provide incentives for compliance.

[920] We note that EEI responds to allegations of undue discrimination in the calculation of load ratio share costs in the OATT Definitions section of this Final Rule.

[921] Order No. 888–A at 30,260–61.

[922] PNM–TNMP and TranServ.

Commission Determination

1626. The Commission concludes that the posting of additional curtailment information is necessary to provide transparency and allow customers to determine whether they have been treated in the same manner as other transmission system users, including customers of the transmission provider. A primary goal of this rulemaking is to remove opportunities for transmission providers to unduly discriminate in favor of their own or their affiliates' use of the transmission system. Making transparent details concerning transmission curtailments so that regulators and customers can verify that the transmission provider curtailed services in accordance with its OATT is entirely consistent with this goal. Commenters who oppose greater curtailment transparency offer no convincing evidence to suggest that any harm or hardship of doing so outweigh the benefits.

1627. We agree with suggestions for the posting of additional curtailment information on OASIS and, therefore, require transmission providers, working through NAESB, to develop a detailed template for the posting of additional information on OASIS regarding firm transmission curtailments. Transmission providers need not implement this new OASIS functionality and any related business practices until NAESB develops appropriate standards. These postings must include all circumstances and events contributing to the need for a firm service curtailment, specific services and customers curtailed (including the transmission provider's own retail loads), and the duration of the curtailment. This information is in addition to the Commission's existing requirements: (1) When any transmission is curtailed or interrupted, the transmission provider must post notice of the curtailment or interruption on OASIS, and the transmission provider must state on OASIS the reason why the transaction could not be continued or completed; (2) information to support any such curtailment or interruption, including the operating status of facilities involved in the constraint or interruption, must be maintained for three years and made available upon request to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it; and, (3) any offer to adjust the operation of the transmission provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted transmission customers at the same time.

1628. The Commission rejects TDU Systems' proposal to require reports filed with the Commission regarding Level 5 TLRs or to require transmission providers to conduct investigations into the need for network upgrades when TLR 5 procedures are repeatedly employed. TDU Systems' proposal is unnecessary at this time in light of our requirement that OASIS templates for curtailment information be developed that will report occurrences of all levels of TLRs. This will enable the Commission and customers to monitor TLR patterns and frequency. Furthermore, the requirements imposed in this Final Rule for congestion studies as part of the coordinated, open and transparent planning requirement will allow stakeholders in the transmission provider's planning process to request studies of those portions of the transmission system where they have encountered transmission problems due to frequent and recurring constraints.

1629. The Commission rejects the three proposals suggested by Powerex. First, it is not necessary to provide early curtailment notification through the OASIS ''recall'' function since the OASIS currently provides a curtailment notification function. Transmission providers should continue to use the OASIS Schedule Details template to post information on the scheduled uses of the transmission system and any curtailments and interruption thereof. Second, with respect to Powerex's request to credit customers when their non-firm point-to-point transmission service is interrupted, we find it unnecessary to modify the *pro forma* OATT to adopt such crediting procedures, consistent with our finding in Order No. 888–A that proper crediting would vary depending on the specific rate design a company uses.[923] Third, we believe that pro-rating curtailments based on reservations would have the potential to impair reliability since the amount of capacity actually curtailed using this approach would not address actual power flows and, therefore, may be less than required to relieve the overloaded facility.

1630. The Commission also rejects TDU Systems' recommendation to refund transmission charges to curtailed customers as a means of disciplining instances of improper curtailments or transmission providers' overselling their systems. We also reject proposals to remedy improper curtailments through refunds of transmission charges to curtailed customers or imposing generic penalties. Rather, the Commission believes that addressing allegations of inappropriate curtailment practices or transmission providers overselling their transmission system are more effectively administered by the Commission on a case-by-case basis.

1631. With respect to the proposal to require redispatch to be performed to the fullest extent prior to curtailments, Manitoba Hydro itself notes that the proposal is intended to address curtailment and redispatch practices unique to MISO. Therefore we conclude that Manitoba Hydro's concerns are best addressed on a case specific basis.

1632. Regarding Seattle's proposal to require what it characterizes as ''reliability redispatch'' to benefit and be paid by all customer classes, we note that this proposal would require expansion of the network service ''reliability redispatch'' provisions to apply to point-to-point service as well. The network service ''reliability redispatch'' provisions in *pro forma* OATT sections 33.2 and 33.3 were established in Order No. 888 to ensure comparable reliable service to network customers as the service that the transmission provider provides to its bundled retail load. These redispatch procedures further provide for redispatch of not just the transmission provider's own resources, but all network resources, including those of network customers, when required to maintain the reliability of the system and avoid the need for curtailments. Seattle has not demonstrated that its proposal to extend ''reliability redispatch'' for point-to-point service is required to ensure comparable, not unduly discriminatory transmission service and has not addressed why network customer resources should be redispatched for the benefit of point-to-point customer. Accordingly, we decline to adopt Seattle's proposal. We discuss redispatch issues more broadly in section V.D.1 of this Final Rule.

[923] *See* Order No 888–A at 30,276. In *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,549 (1997), the Commission clarified that where a transmission provider has not proposed an express crediting provision for the interruption of non-firm point-to-point customers, the transmission provider must compute its bill to an interrupted non-firm customer as if the term of service actually rendered were the term of service reserved. In other words, if a customer with a weekly reservation was interrupted after one day, its bill must be computed as if it had a daily reservation, and if a customer with a daily reservation was interrupted after ten hours, its bill must be computed using the hourly rate applied to ten hours of service.

9. Standardization of Rules and Practices

a. Business Practices

1633. In Order No. 888, the Commission required each public utility that owns, controls, or operates facilities used for transmitting electricity in interstate commerce to file, pursuant to section 205 of the FPA, a *pro forma* OATT under which it would provide open access transmission services. However, certain rules, standards, and practices governing the provision of transmission service (*e.g.*, public utility business practices) are not reflected in the *pro forma* OATT. Only when a public utility adopts a rule, standard, or practice that significantly affects its rates and services has the Commission required it to make a filing pursuant to FPA section 205 to amend its OATT.[924] The Commission has applied this policy using a ''rule of reason'' test.[925]

NOPR Proposal

1634. In the NOPR, the Commission proposed not to modify its existing policy regarding the inclusion of rules, standards and practices in a transmission provider's OATTs. The Commission expressed concern that requiring transmission providers to include all of their rules, standards, and practices in their OATTs could decrease a transmission provider's flexibility to change business practices and respond to the requests of its customers. The Commission also expressed a belief that requiring transmission providers to file all of their rules, standards, and practices in their OATTs would be impractical and potentially administratively burdensome.

1635. The NOPR further noted that there is broad consensus that rules, standards, and practices not required to be included in a transmission provider's *pro forma* OATT should be posted on the transmission provider's OASIS. The Commission agreed and proposed to require transmission providers to post on OASIS all of their rules, standards, and practices that relate to transmission services. The Commission sought comment on how best to determine what ''relates'' to transmission service to facilitate a consistent interpretation and to minimize discretion on what rules, practice and standards should be posted on OASIS.

1636. On the particular issue of creditworthiness and security requirements, the Commission preliminarily concluded that the mere posting of information on OASIS was insufficient. The Commission proposed that each transmission provider's OATT contain sufficient information about its credit process and requirements to enable customers to understand the information required to demonstrate creditworthiness and to determine for themselves the general amount and type of security they may need to provide in order to receive service. The Commission therefore proposed to amend section 11 of the *pro forma* OATT on creditworthiness to require each transmission provider to include its creditworthiness and security requirements in a new Attachment L to its OATT. Consistent with the Creditworthiness Policy Statement,[926] the Commission proposed to require the new Attachment L to include such qualitative and quantitative criteria necessary to determine the level of secured and unsecured credit required, with supplementation in a credit guide or manual to be posted on OASIS.[927] The Commission sought comment on whether the proposal is unduly burdensome.

Comments

Included in Open Access Transmission Tariffs

1637. Many commenters express support for the continuation of the current Commission policy which requires the inclusion in the transmission provider's OATT of only those rules, standards and practices that significantly affect transmission rates and services.[928] These commenters generally state that any rule, practice, term or condition that could result in limiting access to transmission services, including rates and charges for service, should be included in the OATT and should be subject to Commission scrutiny. Examples given include all rules and practices affecting calculation of ATC, creditworthiness criteria, and rules or practices affecting the transmission provider's regional planning process. Commenters argue that Commission oversight is necessary to ensure that these rates, charges, rules, practices, terms or conditions of transmission service are reasonable and afford comparable treatment for wholesale customers.

1638. Other commenters advocate further inclusion of rules, standards and practices in the transmission provider's OATT. Morgan Stanley believes that business practices manuals should be incorporated into each OATT and filed with the Commission for approval. Morgan Stanley states that if this is not required then, at a minimum, each OATT should provide for a process to use when the transmission provider wishes to amend its business practices manuals. For example, transmission providers should provide notice to all affected parties of an intent to make a change, a mechanism to receive stakeholder feedback on the proposed change, and a minimum period of time between the final implementation decision and the effective date of the proposed change (*e.g.*, 30–60 days after final decision). Southwestern Coop, however, maintains that transmission providers should not be allowed to change their rules, standards and practices that affect the justness and reasonableness of OATTs without prior Commission review. Southwestern Coop states that the Commission should require all rules, standards and practices relating to transmission services to be included in the OATT filed with the Commission, because otherwise it cannot ensure that jurisdictional rates are just and reasonable.

Posted on OASIS

1639. Many commenters also express support for the proposed requirement that all rules, standards and practices that are not required to be included in a transmission provider's OATT and that affect a transmission provider's provision of transmission service be posted on OASIS.[929] Commenters generally state that these postings will allow for increased transparency, while affording the transmission provider flexibility to make revisions rather than

[924] *E.g.*, *Cleveland* v. *FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985).

[925] *See, e.g.*, *Public Serv. Comm'n of N.Y.* v. *FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt with only matters of ''practical insignificance'' to serving customers); *Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,137 at 61,401 (''It appears that the proposed Operating protocols could significantly affect certain rates and service and as such are required to be filed pursuant to section 205.''), *order granting clarification*, 100 FERC ¶ 61,262 (2002).

[926] *Policy Statement on Electric Creditworthiness*, 109 FERC ¶ 61,186 (2004) (Creditworthiness Policy Statement).

[927] The Commission proposed to require the new Attachment L to include the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

[928] *E.g.*, ISO/RTO Council, CAISO, LDWP, MISO/PJM States, PGP, and PNM–TNMP.

[929] *E.g.*, CAISO, EEI, MidAmerican, MISO/PJM States, Nevada Companies, PJM, Powerex, Santa Clara, Suez Energy NA, TDU Systems, and TAPS.

having to amend the OATT each time a change occurs.

1640. Powerex argues that the transmission provider also should be required to post data used to calculate ATC, any metrics the Commission adopts regarding the transmission provider's performance of system impact and facilities studies, information concerning both planned and unplanned transmission outages, and a transmission provider's business practices, tariff, organizational charts and job descriptions of its employees.

1641. Southern takes issue with the use in the NOPR of the phrase ''all of their rules, standards and practices,'' stating that language suggests that a transmission provider might be required to reduce each detail of its business practices to writing, which could be overly burdensome. In addition, Southern believes that any rule relating to posting requirements on OASIS should have certain mechanisms to allow the transmission provider to deviate from posted practices when necessary. In contrast, ELCON states that any rule, standard or practice used by the transmission provider and any of its employees to approve or disapprove a request for service should be committed to writing and posted. Similarly, TranServ argues that transmission providers should be required to post on OASIS any criteria applied by the transmission provider to any attribute of a transmission or ancillary service request for the purpose of determining whether the service request should be approved or denied.

1642. Northwest IOUs suggests that the Commission should adopt a ''rule of reason'' test for matters required to be posted on the OASIS similar to the test applied to matters required to be included in the OATT.

Creditworthiness

1643. Several commenters support the inclusion of a separate Attachment L to the *pro forma* OATT outlining creditworthiness requirements, asserting that Attachment L will standardize credit procedures and security requirements and increase transparency.[930] Suez Energy NA states that the proposal is not unduly burdensome, that the procedures proposed are not different from the Creditworthiness Policy Statement or the procedures already imposed in individual cases, and that the Commission is merely proposing to apply an existing requirement in a non-discriminatory manner.

1644. Other commenters propose modifications to the credit-related proposals set forth in the NOPR. TAPS urges the Commission to require the transmission provider to adopt a two-part creditworthiness assessment in order to facilitate non-burdensome and fair assessment of creditworthiness. TAPS recommends that a standard similar to the Florida Power Corp. OATT be applied, which provides that customers with ''satisfactory long-term payment history'' and a minimum credit rating of Baa2 (Moody's) or BBB (S&P) would not have to post any credit security. If a customer fails to meet the threshold test, TAPS states that the transmission provider would perform a transparent credit assessment that is consistent with the Commission's Creditworthiness Policy Statement and the credit policies developed for use in regional transmission organizations such as MISO and SPP. According to TAPS, since quantitative measures sometimes understate public power creditworthiness, transmission providers will need to weigh qualitative factors more heavily than quantitative factors in assessing public power creditworthiness. For public entities that fail the threshold test, TAPS states that transmission providers should use outstanding bond indebtedness as a proxy for tangible net worth for those entities whose energy and transmission service payments receive priority over bond payments.

1645. PJM generally agrees with the creditworthiness proposals, except for inclusion in the OATT of the actual detailed algorithms used to calculate credit scores, stating that those algorithms, as the Commission recognized,[931] may change over time. In PJM's view, requiring all such changes to be approved by the Commission would be unnecessarily burdensome to both the Commission and the transmission provider. PJM recommends that the overall framework of the credit determinations be included in the OATT, while the detailed algorithms be posted on OASIS to meet transparency goals. PJM also recommends that the Commission accept, as an option, a regularly-updated posting on the transmission provider's Web site of each customer's available credit and collateral requirement as sufficient notification for most changes in credit available and credit requirements. PJM further recommends that only significant and sudden reductions in credit available (for example, those greater than 25 percent within a one-month period) be subject to an active notification requirement.

1646. TVA recommends the Commission consider two fundamental principles as it standardizes creditworthiness terms and conditions. First, as long as qualitative factors are part of the equation (and TVA agrees that they should be), TVA states that certain subjective judgments by the transmission provider will be required. TVA encourages the Commission to provide guidance on appropriate criteria to consider in making these judgments, but not to remove entirely from the process the flexibility necessary for individual assessments of customer creditworthiness. Second, TVA states that transmission providers may have to impose different security requirements as a result of differences in statutes, regulations, or other legal requirements. For example, TVA states that its ability to incur debt is limited by section 15d(a) of the Tennessee Valley Authority Act[932] and, therefore, it may need to impose security requirements that are stricter than those of a public utility, as the Commission has previously recognized.[933] TVA requests that the final rule respect these differing legal obligations and provide corresponding flexibility in credit decisions among transmission providers.

1647. A number of commenters oppose the Commission's proposed creditworthiness policy.[934] In general, these commenters believe that each transmission provider should have the flexibility to make and change creditworthiness procedures without the delay of obtaining Commission approval. They also argue that the Commission's goal of transparency could be better achieved by requiring the posting of a transmission provider's creditworthiness policy on OASIS.[935] Xcel and MidAmerican assert that the Commission's proposal would decrease a transmission provider's ability to timely respond to changing market and financial conditions and, therefore, creditworthiness and security requirements should simply be posted on OASIS. Southern believes that the Commission should permit but not require transmission providers to file their creditworthiness and security procedures as part of their OATTs.[936]

[930] *E.g.*, APPA, East Texas Cooperatives, Lassen, MISO/PJM States, Nevada Companies, NRECA, PGP, Powerex, Southern, Suez Energy NA, TANC, and TAPS.

[931] *See* NOPR at P 456.

[932] 16 U.S.C. 831n–4.

[933] *Citing East Ky. Power Coop., Inc.*, 114 FERC ¶ 61,035 at P 56 (2006).

[934] *E.g.*, MidAmerican, Southern, PNM–TNMP, NorthWestern, and Xcel.

[935] *E.g.*, PNM–TNMP, EEI, and MidAmerican.

[936] Southern states that it already includes creditworthiness and security requirements in its

Southern also asks that the Commission allow a transmission provider, in its compliance filing, to request a determination that its current creditworthiness policies and practices are acceptable under the new Commission policies. Similarly, ISO-New England states that this rulemaking should not modify the ISO-New England Financial Assurance and Billing Policies, which are already on file with the Commission.

1648. CAISO states that although the NOPR requirements concerning credit and security requirements do not appear unduly burdensome, it is concerned that the Commission may apply these requirements in a manner that will impose an undue burden on transmission providers and effectively eliminate the ability of transmission providers to supplement basic elements with a credit guide or manual. CAISO and MidAmerican further state that there is no legitimate reason to treat credit policies and procedures any differently than the other rules, practices and standards that the Commission permits to be included on OASIS and does not require to be filed as part of the tariff. Santa Clara recommends that if the Commission decides to require creditworthiness and security policies to be posted on OASIS rather than included in the OATT, then it should require at least a 30-day notice period for changes in the credit policies.

Commission Determination

1649. The Commission adopts the NOPR proposal to continue to require only those rules, standards, and practices that significantly affect transmission service be incorporated into a transmission provider's OATT. The Commission further affirms the use of a ''rule of reason'' to determine what rules, standards, and practices significantly affect transmission service and, as a result, must be included in the transmission provider's OATT.

1650. The ''rule of reason'' test has arisen primarily with respect to protocols or operating procedures used by RTOs and ISOs. For example, the Commission has held that, while MISO's business practices manuals implicate the Commission's jurisdiction because they generally involve ''the installation, operation, or use of facilities for the transmission or delivery of power in interstate commerce,'' they do not require an FPA section 205 filing because ''they mostly involve general operating procedures.'' In other cases, the facts have required the filing of the rule, standard or practice. For example, CAISO proposed to post certain technical, operational and business standards related to dynamic scheduling on its Web site and include only the rates under its OATT. In that instance, the Commission found that the details contained in the standards were practices that could significantly affect the terms and conditions of service and, therefore, under the Commission's ''rule of reason'' must be filed under section 205 of the FPA.[937]

1651. Comments received in response to the NOPR confirm that there is broad support for the Commission's existing practice, requiring only those rules, standards, and practices that significantly affect transmission service, and the use of the ''rule of reason'' test to identify those rules, standards, and practices. The Commission disagrees with parties arguing that all of a transmission provider's rules, standards, and practices should be incorporated into its OATT. We believe that requiring transmission providers to file all of their rules, standards and practices in their OATTs would be impractical and potentially administratively burdensome.

1652. The Commission instead requires transmission providers to post on their public Web sites all rules, standards, and practices that relate to transmission service and provide a link to those rules, standards, and practices on OASIS. We conclude that it would not be appropriate to place the rules, standards, and practices only on OASIS as some transmission providers use certificates to restrict access to their OASIS sites. By providing a link on OASIS to the rules, standards, and practices that are otherwise publicly posted, the Commission ensures that all potential customers will have access to the information necessary for them to understand the terms and conditions of service. We amend section 4 of the *pro forma* OATT to expressly establish this posting requirement.

1653. We note that we already require certain rules and practices to be posted on OASIS.[938] We find that it is now necessary to also require that all rules, standards or business practices that relate to the terms and conditions of transmission service, and how that transmission service is provided to customers, to be detailed, clearly stated on the transmission provider's public Web site, with a link to this information on OASIS.[939] We emphasize that this requirement applies to all such rules, standards, and practices, currently written or otherwise.[940] While we acknowledge this requirement will result in some burden to transmission providers, we find that this approach is necessary to provide greater transparency and mitigate the potential for undue discrimination against customers taking service under the transmission provider's OATT. Further, our holding is not intended to eliminate all discretion under the *pro forma* OATT; rather, we recognize that certain tariff provisions require consideration of the specific facts and circumstances related to particular service requests.[941] We merely require that, if the transmission provider uses standards, rules or business practices to administer its OATT, such standards, rules or business practices must be available for public inspection. Moreover, we note that our actions here are consistent with actions we have taken in recent proceedings. For example, the Commission has required that certain business practices manuals be posted

OATT since the Commission issued its Creditworthiness Policy Statement.

[937] *California Independent System Operator Corp.*, 107 FERC ¶ 61,329 at P 21–22 (2004); *see also Southwest Power Pool, Inc.*, 112 FERC ¶ 61,303 at P 25 (requiring that the SPP OATT provide sufficient information for market participants to fully understand SPP's implementation of an imbalance market), *reh'g denied*, 113 FERC ¶ 61,115 (2005); *PJM Interconnection, L.L.C.*, 104 FERC ¶ 61,124 at P 61 (requiring PJM to place all procedures, standards and requirements for proposing that a transmission owner construct a specific upgrade, and all procedures for charging customers, in its tariff, not in its manuals), *order on reh'g, PJM Interconnection, L.L.C.*, 105 FERC ¶ 61,123 (2003).

[938] *See, e.g.*, Order No. 889 at 31,588–89; *Open Access Same-Time Information Systems*, Order No. 605, 64 FR 34117 (Jun. 25, 1999), FERC Stats. and Regs. ¶ 31,075 (1999); Order No. 676 at P 79.

[939] If a particular rule, standard or practice conflicts with an OATT provision, the OATT of course shall govern in all circumstances. Moreover, as noted in the NOPR, we emphasize that posting rules, practices and standards—in lieu of filing such practices with the Commission as part of the transmission provider's *pro forma* OATT—neither insulates a transmission provider from complaints nor confers a just and reasonable presumption. We encourage customers to call the Commission's Enforcement Hotline with complaints about the application of such rules, standards and practices should they experience problems with their transmission providers. To the extent customers are not satisfied with responses from their transmission provider, they should contact the Commission's Enforcement Hotline via telephone (202) 502–8390, toll-free 1–888–889–8030, fax (202) 208–0057, or at *http://www.ferc.gov/cust-protect/enforce-hot.asp.*

[940] With respect to the business practices developed by NAESB, there may be certain copyright restrictions that limit the transmission provider's ability to post those practices on its own Web site. In such instances, we expect that the transmission provider will reference any NAESB practices it uses and provide a link on its public Web site to the NAESB Web site in order to provide interested parties with a means to access the copyrighted material.

[941] The circumstances and manner in which a transmission provider exercises its discretion under its OATT must be posted in accordance with 18 CFR 37.6(4).

and made available for public view on a permanent basis.[942] As in those cases, we find that making rules, standards, and practices readily accessible will serve as a tool to supplement each transmission provider's OATT and facilitate fair and open access to the transmission grid.

1654. To provide guidance to the transmission providers as to whether a particular rule, standard, or practice ''relates to'' transmission service, and therefore warrants posting, the Commission believes the MAPP Policies and Procedures for Transmission Operations manual is a good example of the type of information that relates to the terms and conditions of transmission service. For example, the MAPP manual sets forth information supplementing its OATT pertaining to (1) transmission service requests on the MAPP OASIS site, (2) the retraction of an accepted or counteroffer transmission request, (3) timing requirements for transmission service requests, (4) methods to accommodate a firm transmission request with redispatch, and (5) transmission service charge implementation procedures. Other examples include detailed information regarding tagging, scheduling, billing and other matters provided in other RTO manuals. This is the type of information that clearly relates to transmission service and therefore must be reduced to writing and publicly posted.

1655. We also agree with requests to require a transparent process for amending rules, standards, and practices previously posted by a transmission provider. We therefore require each transmission provider also post on its public Web site (with a corresponding link on OASIS) a statement of the process by which the transmission provider will amend these rules, standards, and practices that are accessible via OASIS. As part of this process, the transmission provider must specify a mechanism to provide reasonable notice of any proposed changes to a posted business practice and the respective effective date of such change.[943] We amend section 4 of the *pro forma* OATT to formalize this posting requirement and obligate transmission providers to follow the amendment procedures specified by the transmission provider. As with the requirement to post the underlying standards, rules and practices, we believe the amendment procedures required here will increase transparency and help minimize opportunities for undue discrimination.

1656. The Commission also adopts the NOPR proposal and amend the *pro forma* OATT to include a new Attachment L.[944] We find that the transmission provider's basic credit standards significantly affect transmission service and, therefore, must be included in the *pro forma* OATT. This will ensure that all customers have clear information as to the credit process and standards used by a transmission provider to grant or deny transmission service and, in turn, will serve to prevent undue discrimination and eliminate a potentially significant barrier to entry in the provision of service. Most importantly, by making Attachment L a part of the *pro forma* OATT, customers will have an opportunity to comment on any changes to the standards proposed by a transmission provider in a rate filing with the Commission.

1657. To that end, each transmission provider's Attachment L must specify the qualitative and quantitative criteria that the transmission provider uses to determine the level of secured and unsecured credit required. Attachment L must also contain the following elements: (1) A summary of the procedure for determining the level of secured and unsecured credit; (2) a list of the acceptable types of collateral/security; (3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements; (5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and (6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination. We will allow the transmission provider to supplement Attachment L with a credit guide or manual to be posted on OASIS.

1658. We disagree with commenters that claim requiring this information in an attachment to each transmission provider's OATT will hinder the transmission provider's ability to timely respond to changing market and financial conditions. Because Attachment L requires only a summary of credit requirements and other information, we expect the need to revise Attachment L will occur infrequently. As suggested by PJM, detailed information, such as the algorithms used by the transmission provider to determine credit scores, can be posted on OASIS along with other information that relates to the provision of transmission service. Thus, the requirement we are imposing should not be overly burdensome.

1659. At the same time, we agree that transmission providers need flexibility in determining credit requirements in light of qualitative and quantitative factors, as we recognized in the NOPR and the Creditworthiness Policy Statement. We believe the requirements adopted in this Final Rule allow for such flexibility. By requiring transmission providers to consider both quantitative and qualitative factors, the particular circumstances surrounding public power entities can be recognized. We agree, moreover, with TVA that the transmission provider's credit policies must be consistent with its legal obligations and expect that interested parties will bring any legal conflicts to our attention on review of the transmission provider's compliance filing.

1660. With regard to requests to find existing credit policies consistent with the requirements of the Final Rule, all transmission providers will be required to demonstrate compliance with all aspects of the Final Rule either by implementing the reforms adopted today or showing that departures are consistent with or superior to the terms and conditions of the *pro forma* OATT, as modified by this Final Rule. The procedural mechanisms for making such a showing provided for in section IV.C above give transmission providers the opportunity to demonstrate that retention of their existing credit practices is appropriate.

1661. Finally, with regard to Santa Clara's request to require the transmission provider to provide at least a 30-day notice period for changes in creditworthiness and security policies that are posted on OASIS, we explain above that each transmission provider must identify and incorporate a specific process in its OATT for amending business practices that are posted on OASIS. Such practices include those

[942] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 658, *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043, *order on reh'g*, 112 FERC ¶ 61,086 (2005); *see also PJM Interconnection, L.L.C.*, 81 FERC ¶ 61,257 at 62,267 (1997) (finding no reason to require filing of the PJM Manuals but requiring that such manuals be available for public inspection on a permanent basis), *order on reh'g*, 92 FERC ¶ 61,282 (2000).

[943] As part of their business practice amendment procedures, transmission providers may adopt such additional procedures they deem appropriate, such as opportunities for comment to proposed changes to rules, standards, and practices.

[944] As with new Attachment K to the *pro forma* OATT, regarding transmission planning, we acknowledge that some transmission providers may already have attachments to their OATTs labeled with the letter ''L,'' in which case transmission providers are free to label their credit procedures OATT attachment with the next available letter.

that describe and implement its creditworthiness and security policies.

b. Liability and Indemnification

1662. In Order No. 888, the only liability provisions included in the *pro forma* OATT related to force majeure and indemnification.[945] Section 10.1 of the *pro forma* OATT provides that neither the transmission provider nor the transmission customer will be considered in default as to any obligation under the tariff if prevented from fulfilling the obligation due to an event of force majeure. A party whose performance under the tariff is hindered by an event of force majeure, however, is required to make all reasonable efforts to perform its obligations under the tariff. With respect to indemnification, under section 10.2 of the *pro forma* OATT, the transmission customer indemnifies the transmission provider against third party claims arising from the transmission provider's performance of its obligations under tariff on behalf of the transmission customer, except in cases of negligence or intentional wrongdoing by the transmission provider.

(1) Force Majeure

Comments

1663. Santa Clara queries whether the Commission intended to make the transmission provider's performance of its obligations less burdensome by using the phrase ''all reasonable efforts'' instead of ''due diligence'' in the force majeure provision in section 10.1 of the *pro forma* OATT is. In either case, Santa Clara requests the Commission to consider the use of the most stringent term when addressing a transmission provider's obligation to perform under its tariff.

Commission Determination

1664. The Final Rule retains the current ''all reasonable efforts'' standard in the force majeure provision. Santa Clara does not explain how the ''all reasonable efforts'' standard may be more or less stringent than the ''due diligence'' standard. Further, as the Commission explained in Order No. 888, this protection against unexpected and unpredictable events is appropriately made available to both the transmission provider and transmission customer. We therefore find that the clarification requested by Santa Clara is unnecessary.

[945] Order No. 888–B at 62,081

(2) Indemnification/Limitation of Liability

Comments

1665. Several commenters[946] urge the Commission to change the indemnification provision to protect transmission providers from liability except in the case of gross negligence or intentional misconduct, thereby exempting the transmission provider from liability for acts of ordinary negligence. These commenters also request that the Commission add to the *pro forma* OATT a new provision clarifying that the transmission provider would not be liable to any transmission customer or third party for direct, incidental, consequential, indirect, or punitive damages arising from services provided under the tariff, except in cases of gross negligence or intentional misconduct (in which case, EEI, and Northwest IOUs propose, liability would be limited to direct damages). These commenters note that the Commission has allowed transmission providers this protection in the tariffs of MISO, PJM, ISO New England, SPP, and their member transmission owners and generators, but it has not fully explained its basis for treating non-RTO member transmission providers differently from RTOs and ISOs. EEI further notes that the Commission accepted similar liability protection in the Large Generator Interconnection Agreement (''LGIA'') and in natural gas pipeline tariffs.[947] EEI requests that this liability limitation be added to the *pro forma* transmission service agreement that would apply to transmission customers acting in good faith to carry out the directives of a transmission provider.

1666. With respect to third party indemnification, EEI notes that the Commission reasoned in SPP that, even though a broader liability limitation would relieve a transmission provider from liability for ordinary negligence, that provision only applies to transmission customers under the tariff. EEI states that there are many other entities that could initiate legal action against the transmission provider in connection with the provision of transmission service, thereby making an adequate indemnification provision in the *pro forma* OATT necessary for the same reasons as the limited liability provision.[948]

[946] *E.g.*, Southern, EEI, and Northwest IOUs.

[947] *Citing* Article 18, Large Generator Interconnection Agreement; *ANR Pipeline Co.*, 98 FERC ¶ 61,218, *order on tariff filing*, 100 FERC ¶ 61,132 (2002).

[948] *Citing Southwest Power Pool, Inc.*, 112 FERC ¶ 61,100 at P 39 (2005).

1667. EEI contends that the addition of the Commission's new EPAct 2005 authority to establish mandatory reliability standards to provide open access transmission service to all customers, regardless of their risk profile, makes it an appropriate time to revisit the liability provisions in the OATT. According to EEI, a limitation on liability in the *pro forma* OATT should be viewed as a necessary element of the implementation of the Commission's reliability authority. Because transmission providers cannot deny service to particular customers based on the risk of potential damages, EEI and Southern assert that all transmission providers should be protected from certain risks associated with this obligation to serve. EEI argues that increased protection from liability would lower the cost of capital for new transmission projects and promote the expansion of transmission infrastructure. EEI further argues that the technological complexity of modern utility systems and the potential for service interruptions unrelated to human errors justify liability limitations. According to EEI, a limitation on liability to direct damages puts the risk on those customers with special reliability needs, rather than spreading the risk among all customers.

1668. EEI notes that the Commission has denied requests for exemptions from liability for ordinary negligence in the indemnification provision on the grounds that liability and indemnification were ''separate issue[s]'' and that transmission providers seeking liability protections could rely on state laws.[949] EEI argues, however, that an OATT and the accompanying service agreement constitute a contract between the transmission provider and the customer that is established pursuant to federal law and, as a result, it is not at all clear that a state law limitation on liability would apply. Southern asserts that adopting liability limits would provide uniformity, certainty, and reduce risk since reliance on state law is an issue not free from doubt.

1669. Entegra argues on reply that the NOPR did not contemplate any modification to these provisions of the *pro forma* OATT and neither EEI nor Southern has established a nexus between such a modification and the goals set forth in the NOPR. TDU Systems on reply similarly argue that EEI's request is outside the scope of the rulemaking and neither EEI nor Southern show a change in circumstance justifying a new limitation

[949] *Citing* Order No. 888–A at 30,301.

on liability. Immunizing transmission providers from these liability risks, TDU Systems contend, would simply transfer risk to customers that have no control over the transmission provider's negligence. Entegra and TDU Systems further argue that Southern previously sought the same relief in a tariff filing rejected by the Commission less than a year ago, stating that the Commission thus already rejected the notion that Southern was similarly situated to the RTOs and ISOs that have this protection.[950] Entegra notes that Southern did not seek rehearing of that order and its comments here are therefore an impermissible collateral attack on a final Commission order. As for the argument regarding EPAct 2005, TDU Systems note that the Commission presumably was aware of its new reliability authorities when it issued the *Southern* order four months after EPAct was enacted.

1670. TDU Systems also point out that the tariff language proposed by EEI would not protect a transmission customer from being sued by a third party for the negligence or willful misconduct of the transmission provider. In such lawsuits, TDU Systems claim, a third party would not be limited to direct damages. According to TDU systems, any indemnification as between the transmission provider and the transmission customer that is limited to direct damages would leave the customer holding the bag for the indirect damages caused by the transmission provider's negligence or willful misconduct.

Commission Determination

1671. We will retain the current liability protections in the *pro forma* OATT for the same reasons that the Commission has rejected similar past proposals. While the Commission explained in Order Nos. 888–A and 888–B that the *pro forma* tariff was not intended to address liability issues, as EEI notes, the Commission stated that liability was a separate issue from indemnification.[951] The Commission further explained that transmission providers were not precluded from relying on state laws that protected utilities or others from claims founded in ordinary negligence.[952] The Commission declined to adopt a uniform federal liability standard and decided that, while it was appropriate to protect the transmission provider through force majeure and indemnification provisions from damages or liability when service is provided by the transmission provider without negligence, it would leave the determination of liability in other instances to other proceedings.[953]

1672. On the issue of a negligence standard for the indemnification provision, we decline to depart from our policy set forth in Order No. 888, as affirmed in Order No. 888–A and subsequent orders.[954] In Order No. 888, the Commission stated:

> We have limited the indemnification portion of the provision so that it is now only the transmission customer who indemnifies the transmission provider from the claims of third parties. The customer is taking service from the transmission provider and may appropriately be asked to bear the risks of third-party suits arising from the provision of service to the customer under the tariff. We find that this new indemnification provision would be too strict if it required customers to indemnify transmission providers even in cases where the transmission provider is negligent. Accordingly, the revised provision provides that the customer will not be required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission provider.[955]

1673. The Commission subsequently addressed this issue in *Northeast Utilities.* There, the Commission found that a broader customer indemnification obligation that would include ordinary negligence would not give any incentive to the transmission provider to avoid negligent actions. In *Northeast Utilities,* the Commission explained again why it permitted a gross negligence exception in the *pro forma* LGIA section 18.1 in order to further limit the transmission provider's liability. As the Commission explained in Order No. 2003, interconnection warrants a different standard because it presents a greater risk of liability than exists for the provision of transmission service. The Commission further found that because risk exposure can increase interconnection costs, a broader indemnity standard is appropriate in the interconnection context.[956]

1674. Further, unlike Order No. 888 in which the transmission customer indemnifies the transmission provider, in Order No. 2003 the indemnity provision is expressly bilateral. In Order No. 2003 the interconnecting generator and the transmission provider each indemnifies the other from all damages to third parties arising under the LGIA from conduct on behalf of the indemnifying party, except in cases of gross negligence. Given that the indemnification provision in the *pro forma* LGIA is bilateral, in contrast to the *pro forma* OATT, it is reasonable to permit a gross negligence standard in the case of an interconnection.

1675. We also reject commenters' assertions that the liability standard the Commission has approved for RTOs/ISOs and gas pipelines is appropriate for other transmission providers. In the Reliability Policy Statement,[957] the Commission stated that it would consider, on a case-by-case basis, proposals by public utilities to amend their OATTs to include limitations on liability. The Commission further noted that while this issue has not been resolved on a standardized basis, the Commission has entertained RTO transmission providers' specific proposals to amend their OATTs to include provisions addressing limitations on liability.[958]

1676. In subsequent orders, the Commission found that the gross negligence and intentional wrongdoing indemnification and liability standard is appropriate for RTOs and ISOs. However, the Commission has declined to extend this protection to all transmission providers. In *Southwest Power Pool, Inc.*, the Commission explicitly stated ''that our acceptance here of the gross negligence and intentional wrongdoing indemnity standard is limited to SPP, in its role as an RTO, and its TOs; we do not intend to extend such protection to all transmission providers.'' [959] In *Southern Company Services, Inc.*, the Commission stated that:

> Having considered Southern Companies' proposed limitation on liability and indemnification provisions pursuant to our Reliability Policy Statement cited above, we find that Southern Companies have not shown that they are similarly situated to the RTOs/ISOs they cite in support. While Southern Companies claim that they ''may not be protected by any State-regulated limitations on liability,'' Southern Companies offer no evidence to support this concern. The Commission has provided such liability protection to RTOs/ISOs because they were created by and solely regulated by the Commission, and otherwise would be without limitations on liability. Southern Companies have proffered no evidence of any

[950] *See* Entegra Reply (*citing Southern Company Services, Inc.*, 113 FERC ¶61,239 (2005)).

[951] *See* Order No. 888–A at 30,301 and Order No. 888–B at 62,081 (section 10.2 of the *pro forma* OATT).

[952] Order No. 888–A at 30,301.

[953] Order No. 888–B at 62,081.

[954] *See, e.g., Northeast Utilities Services Co.*, 111 FERC ¶ 61,333 (2005) (Northeast Utilities).

[955] Order No. 888 at 31,765.

[956] Order No. 2003 at P 636; Order No. 2003–A at 31,162.

[957] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 (2004) (Reliability Policy Statement).

[958] Reliability Policy Statement at P 40 (citations omitted).

[959] 112 FERC ¶ 61,100 at P 39 (2005).

change in circumstances vis-à-vis their liability exposure post-Order No. 888.[960]

1677. Commenters offer no new arguments that demonstrate that they are unable to rely on state laws, *i.e.*, the state laws provide inadequate protection. While EEI and Southern assert that there is uncertainty in whether state law on liability would apply to a service agreement between a transmission provider and a transmission customer, we note that neither provide any evidence that transmission providers are actually precluded from relying on state law for liability protection. EEI and Southern thus fail to show that the potential for a legal and regulatory gap is so great as to warrant inclusion of liability protections in the *pro forma* OATT for all transmission providers. In this regard, the Commission also finds without merit assertions that increased liability protections in the *pro forma* OATT should be viewed as a necessary element of the implementation of the Commission's reliability authority. As none of the arguments proffered by commenters persuade us to change our policy regarding liability protections applicable to non-RTO and non-ISO transmission providers, we decline to modify the liability protections in the *pro forma* OATT.

10. OATT Definitions

1678. In order to support the reforms adopted in this Final Rule and otherwise clarify the requirements of the *pro forma* OATT, the Commission adds and amends various definitions in the *pro forma* OATT, as set forth below.

a. Affiliate

NOPR Proposal

1679. In the NOPR, the Commission proposed a new definition of Affiliate incident to the proposed change to the pricing of reassigned capacity.

Comments

1680. Some commenters request clarification that the proposed definition of Affiliate would not apply to transmission-only cooperatives or independent entities such as RTOs. NRECA asserts that in Order No. 2004–A, the Commission concluded that ''[g]eneration and transmission cooperatives (G&T) are not subject to the Standards of Conduct consistent with the policies established under Order No. 888.'' NRECA asks for confirmation that distribution and generation and transmission cooperatives will not be considered affiliates of each other for OATT and Standards of Conduct purposes because recent pleadings reveal that there continues to be confusion about this definition. TranServ asks for clarification of the application of the definition of ''affiliate'' with respect to a merchant affiliate of a transmission provider that has turned over tariff administration functions to an ISO, RTO, or other independent entity. PNM–TNMP suggests that the definition of Affiliate be expanded or clarified to encompass divisions of an entity that operate as a functional unit. PNM–TNMP asserts that such a change would make clear that an Affiliate includes not only separate legal entities, but also may apply to divisions and functional units within the entity.

Commission Determination

1681. As discussed in section V.C.4, the Commission lifts the price cap on reassigned transmission capacity for all transmission customers, regardless of affiliation with the transmission provider. It is therefore no longer necessary to define an affiliate for purposes of that provision. The Commission nonetheless adopts the proposed definition of Affiliate to implement the reforms associated with distribution of operational penalties discussed in section V.C.5.b.

1682. With regard to the request that we clarify that an Affiliate does not apply to transmission-only cooperatives, we agree with NRECA that the Commission made clear in Order No. 888–A that there was no corporate affiliation between G&T cooperatives and their member distribution cooperatives.[961]

1683. TranServ requests clarification regarding the use of the term ''affiliate'' in the context of a transmission owner that has turned over operational control of its transmission facilities to an RTO, ISO, or to an independent entity. We clarify that, for purposes of the distribution of penalties, if such transmission owner is not required to be a transmission provider under a Commission-approved tariff, the merchant affiliate of such transmission owner would not be considered to be an ''affiliate'' of the RTO, ISO, or independent entity under the definition adopted in this Final Rule. The affiliation of a merchant to a transmission owner does not establish an affiliation between such merchant and the RTO, ISO, or independent entity transmission provider.

1684. As to PNM–TNMP's request that the definition of ''affiliate'' be expanded or clarified to encompass divisions of an entity that operate as a functional unit, we note that PNM–TNMP's concern appears to have been raised in the context of lifting the price cap for capacity reassignment, initially proposed only for non–affiliated transmission customers. We believe we have addressed PNM–TNMP's concerns by lifting the price cap for capacity reassignment for all customers, including affiliates of the transmission provider and the transmission provider's merchant function.

b. Good Utility Practice

NOPR Proposal

1685. In the NOPR, the Commission proposed to incorporate the definition of reliable operation from FPA section 215 in the definition of Good Utility Practice in the *pro forma* OATT.

Comments

1686. No commenters oppose the Commission's proposal to modify the definition of Good Utility Practice to reference the reliable operation standard of FPA section 215.

Commission Determination

1687. The Commission adopts the NOPR proposal to incorporate the definition of reliable operation from FPA section 215 in the definition of Good Utility Practice in the *pro forma* OATT. FPA section 215(b) obligates all users, owners and operators of the bulk power system to comply with reliability standards that will take effect under that section. Referencing section 215 in the definition of Good Utility Practice is appropriate to ensure that the reliability standards ultimately developed by the ERO and approved by the Commission are reflected in the *pro forma* OATT.

c. Non-Firm Sales

NOPR Proposal

1688. The Commission proposed to add a definition for Non-Firm Sales to clarify the treatment of such sales under section 30.4 of the *pro forma* OATT.[962] The Commission proposed defining a Non-Firm Sale as ''an energy sale for which delivery or receipt of the energy may be interrupted for any reason or for no reason, without liability on the part of either the buyer or seller.'' The Commission also proposed to clarify that, for the purposes of applying

[960] 113 FERC ¶ 61,239 at P 7 (2005).

[961] Order No. 888–A at 30,286 and 30,366.

[962] Section 30.4 as proposed in the NOPR provides, in relevant part, that ''[t]he Network Customer shall not operate its designated Network Resources located in the Network Customer's or the Transmission Customer's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses.''

section 30.4, energy sales that can only be interrupted to maintain system reliability would be considered firm sales.

Comments

1689. Several commenters argue that the proposed definition of Non-Firm Sales could impede a network customer's ability to obtain transmission service for certain types of energy products. In particular, Duke, EEI, and Southern question the treatment of power purchase agreements with LD provisions under the proposed definition. Duke contends that a contract with an LD provision might be interruptible for any reason, but it would still provide for liability in the form of LD payments. As a result, the LD contract might not fall within the definition of a Non-Firm Sale. At the same time, network customers can only designate resources from system purchases not linked to a specific generating unit if the purchase power agreement is not interruptible for economic reasons, does not excuse seller performance for economic reasons, and requires the network customer to pay for the purchase.

1690. Commenters are thus concerned that some contracts with LD provisions may be too firm to be a Non-Firm Sale, but not firm enough to be designated as a network resource. Duke argues that network customers should be allowed to operate their Network Resources to both serve load and sell a firm LD product. EEI is concerned that the proposed definition of Non-Firm Sales would prohibit a network customer from making an off-system sale of a firm LD product or any other product that does not result in undesignation of a Network Resource, given the restrictions set forth in section 30.4. Duke and EEI therefore propose that a Non-Firm Sale should be defined as any sale that is not sufficiently firm to be designated a Network Resource of the purchasing entity. Raising concerns similar to those raised by Duke and EEI, Southern proposes to define Non-Firm Sales as any sale that does not commit the associated resource to a third party and otherwise keeps the resource available for network service on a non-interruptible basis.

1691. NRECA, however, argues that contracts with LD provisions are typically considered firm products, so long as they cannot be curtailed for economic reasons alone. NRECA requests that the Commission confirm its understanding that the mere inclusion of an LD provision in a contract does not make the sale non-firm, provided that the sale cannot be curtailed only for economic reasons.

Commission Determination

1692. The Commission adopts the proposed definition of a Non-Firm Sale and incorporates that defined term in section 30.4 of the *pro forma* OATT. Network customers may use network resources for third party sales only if the sale is on a non-firm basis. This ensures that the network resource is available to serve the network load on an uninterruptible basis. We conclude that it would be inappropriate, as some commenters suggest, to relax the definition of a Non-Firm Sale to include any sale that is not otherwise firm enough to be designated as a network resource. We address the requirements for designation of network resources in section V.D.6, concluding that not all contracts with LD provisions are sufficiently firm to be eligible for designation. There we explain that only LD provisions that provide for ''make whole'' remedies are sufficiently firm to be designated as network resources. It does not follow, however, that all remaining contracts with LD provisions are non-firm. The very existence of an LD provision indicates that interruption of service will result in liability and, thus, such contracts cannot automatically be considered Non-Firm Sales for purposes of section 30.4. To allow otherwise would create conflicting incentives for the network customer.

d. Pre-Confirmed Application

NOPR Proposal

1693. Incident to the proposal to give priority to requests that are pre-confirmed, the NOPR proposed a new definition of Pre-Confirmed Application.

Comments

1694. No commenters oppose the Commission's proposed definition of a Pre-Confirmed Application.

Commission Determination

1695. The Commission adopts the proposed definition of Pre-Confirmed Application in order to implement the reforms adopted above regarding the priority of transmission service requests under the *pro forma* OATT.

e. NOPR Proposals Not Adopted

Economy Energy

1696. The Commission also proposed in the NOPR to adopt a definition of ''economy energy'' incident to its proposed changes to section 28.4 regarding the use of secondary network service. As discussed in section V.D.7, the Commission retains the existing requirement in section 28.4 that permits use of secondary network service ''to deliver energy to its Network Loads.'' The proposed definition of ''economy energy'' is therefore unnecessary.

f. Commenter Proposals

1697. Several commenters request that the Commission amend or add other definitions in the *pro forma* OATT.

(1) Network Transmission Service

Comments

1698. TDU Systems and Northwest Parties contend that, to help eliminate undue discrimination, the Commission should modify the definitions of ''network load'' and ''network operating committee'' in the *pro forma* OATT. Although the *pro forma* OATT already defines ''network load'' to include wholesale native load, TDU Systems contend that transmission providers frequently either give preference to their own retail native load or ignore wholesale customer native load in planning and expansion of the system and in ATC calculations for processing transmission service requests. TDU Systems argue that comparable treatment of wholesale native load and retail native load is required in all respects in light of the definition of ''network load.'' At the same time, TDU Systems argue that the definition of ''network load'' unreasonably restricts a transmission customer from serving a part of its load at a given delivery point with non-network resources since it provides that a customer ''may not designate only part of the load at a discrete Point of Delivery.''

1699. Northwest Parties also assert that the Commission should revise the definition of ''network load'' to permit point-to-point service and network service to the same network load if the point-to-point service is ignored in calculating load ratio share. Northwest Parties also argue that the Commission should allow point-to-point and network service to the same network load if the point-to-point service is purchased as non-firm.

1700. EEI replies in opposition to TDU Systems' proposal to eliminate the requirement that a network customer may designate only part of its load delivery as a network load. EEI argues that TDU Systems are incorrect in asserting that the definition of ''network load'' prohibits a network customer from serving part of its load with non-network resources and secondary network service to serve part, or even

all, of its network load. EEI contends that adoption of TDU Systems' proposal would eliminate one of the fundamental principles on which network service is founded: That the network customer must pay for network service based on its entire load, including load served by behind the meter generation, since the transmission provider must plan its transmission system to serve the customer's entire load.

1701. PNM–TNMP agree on reply that Commission should reject a change to the definition in the *pro forma* OATT regarding network load. PNM-TNMP state that the proposal presupposes that transmission providers discriminate against transmission customers and provides preferential treatment to their own retail native load in terms of planning and expansion of the system and in ATC calculations for processing transmission service requests. PNM–TNMP contend that they treat retail native load comparably with other network customers in all aspects and believe that any problems encountered by a transmission customer regarding undue discrimination should be addressed through the enforcement or complaint process, and that a change to the *pro forma* OATT is not warranted.

Commission Determination

1702. The Commission declines to modify the definitions of ''network load'' and ''network operating committee.'' The reforms related to ATC calculation and transmission planning adopted in this Final Rule adequately address the concerns regarding undue preference of native load in those areas. With regard to the request to allow network customers to serve part of their load with non-firm point-to-point service and part with network service, the Commission already determined in Order Nos. 888 and 888–A that a transmission customer is not allowed to take a combination of both network and point-to-point transmission service to serve the same discrete load.[963] We are not persuaded to modify that policy here.

(2) Firm and Non-Firm Transmission Service

Comments

1703. Powerex contends that ''firm transmission service'' is not adequately defined or sufficiently described in the *pro forma* OATT to ensure that a transmission customer is not being required to pay for firm service that is curtailed on a regular basis. For example, Powerex states the Commission could require that firm transmission service be available at least 95 percent of the time (excluding force majeure curtailments) in order for transmission to be defined as ''firm.''

1704. Powerex also contends that ''non-firm transmission service'' is interpreted differently in different regions. In the Pacific Northwest, Powerex asserts that non-firm service implies a lower curtailment priority but only as a result of actual transmission system constraints (*i.e.*, once the operating hour has begun, higher priority firm reservations cannot implement schedules over lower priority non-firm reservation). In contrast, Powerex argues that, for some transmission providers located in the Desert Southwest, transmission capacity associated with firm service reservations that have capacity schedules attached to them (*e.g.*, to deliver operating reserves) can also be sold as non-firm service that could be interrupted in the operating hour by the firm reservation. Powerex believes that these two types of service could be described as non-firm, non-interruptible (for the Pacific Northwest) and non-firm, interruptible (for the Desert Southwest).

Commission Determination

1705. The Commission finds that the clarifications proposed by Powerex are unnecessary to remedy undue discrimination in the provision of open access transmission service. In section V.D.8 of this Final Rule, the Commission requires transmission providers to post additional information regarding curtailments in order to provide transparency and allow customers to determine whether they have been treated in the same manner as other transmission system users. We conclude that existing compliance and enforcement procedures, coupled with these new posting requirements, are sufficient to address improper curtailments of service.

(3) System Impact Study

Comments

1706. Powerex urges the Commission to modify sections 1.47 and 17.5 of the *pro forma* OATT to clarify that transmission providers are not required to perform system impact studies for short-term service requests. Specifically, Powerex requests that the Commission amend the definition of a ''system impact study'' to refer only to requests for long-term firm point-to-point service or network service. Powerex argues that short-term firm point-to-point service requests do not require transmission providers to upgrade their systems and, as a result, requiring system impact studies for short-term requests often creates unnecessary burdens for transmission providers by mandating them to use limited resources to perform studies that do not offer significant benefits to customers. Powerex contends that the 60-day study period is particularly ill-suited for short-term transmission requests, most of which are for service that must commence within the study period.

Commission Determination

1707. The Commission declines to modify the definition of ''system impact study'' or otherwise modify section 17.5 to restrict system impact studies only to exclude reference to short-term point-to-point service. Regardless of the length of a service request, a transmission provider must assess whether a system impact study is required to evaluate the request for transmission service. Only upon the completion of such an assessment will the transmission provider be able to identify the impact a particular request will have on the grid. We conclude that eliminating or shortening the system impact study period could jeopardize system reliability and therefore reject the modifications proposed by Powerex.

(4) Definitions for RTOs, ISOs and ITCs

Comments

1708. Wisconsin Electric and International Transmission argue that the terms used in the *pro forma* OATT are inadequate when applied to RTO regions, especially in MISO. International Transmission and Wisconsin Electric assert that, in an RTO, the transmission provider and transmission owner are separate entities with separate functions, thus creating a need for separate definitions. They also contend that additional definitions may be needed when the transmission owner is an independent stand-alone transmission company operating within the RTO.

1709. Wisconsin Electric requests that the Commission define the term ''transmission owner'' in the *pro forma* OATT and specify which of its provisions are applicable to the transmission provider and which apply to the ''transmission owner.'' Additionally, Wisconsin Electric states that the *pro forma* OATT includes a definition for ''control area'' and the NOPR refers to the geographic area served by transmission providers as its control area, which in Wisconsin Electric's view is inaccurate in the case of MISO. Wisconsin Electric explains MISO has shifted to the use of the NERC

[963] *See* Order No. 888 at 31,736; Order No. 888–A at 30,259.

functional model and uses terms such as ''balancing authorities,'' ''generator operators,'' ''reliability authorities,'' and the like. Wisconsin Electric therefore requests that the Commission supplant the term ''control area'' in the *pro forma* OATT with a term that is predicated on the performance of a particular function, not the type of entity performing the function.

1710. International Transmission does not object to the Commission's proposal to largely retain the existing definitions set forth in the *pro forma* OATT, but asserts that the Commission should explicitly recognize in the Final Rule that such definitions may be inadequate when applied to RTOs. International Transmission also asks the Commission not to require RTOs with additional definitions in their tariffs to remove those definitions when complying with the Final Rule and, instead, expressly allow RTOs to propose additional definitions that may be necessary.

Commission Determination

1711. As explained in section IV.C, all transmission providers—including ISOs and RTOs—will have an opportunity to demonstrate that departures from the *pro forma* OATT, as modified by this Final Rule, are consistent with or superior to the terms and conditions of the *pro forma* OATT. Proposals to amend terms such as ''control area'' or ''transmission owner'' based on a particular set of facts are best left for case-by-case review.

(5) Other Definitions

Comments

1712. Ameren advocates the modification of a number of other *pro forma* OATT definitions. Ameren proposes definitions for ''source'' and ''sink,'' as well as additional provisions in section 22.2 governing source and sink of transmission. Ameren also requests clarification of the word ''use'' in section 30.8, arguing that some entities have assumed that ''use'' means scheduled amounts. Ameren argues for an improved definition of ''transmission peak'' because the data necessary no longer resides with the transmission owner in an RTO or ISO. Finally, Ameren suggests a revised definition of ''long-term firm,'' which would include only contracts that are longer than one year, not just one year or longer, arguing it would reduce the number of contracts that are only one-year in length that are used in the denominator for purposes of calculating the load ratio share and for ratemaking purposes. On this latter point, Ameren asserts that such contracts should be reflected as a revenue credit instead. In addition, Ameren believes that the current definition of long-term firm point-to-point service in section 1.18 of the *pro forma* OATT makes calculation of load ratio share very difficult in the modern RTO/Seams Elimination Cost Allocation (SECA) environment.

Commission Determination

1713. The Commission is not persuaded to adopt the revisions proposed by Ameren. We believe that what constitutes source and sink is sufficiently addressed in Order No. 888 and OASIS related proceedings and we will not expand the discussion here.[964] Order No. 888 also made clear that there are no ''load ratio'' limitations on the use of interfaces under section 30.8 of the *pro forma* OATT.[965] Otherwise, requests for interface capacity are subject to the *pro forma* OATT procedures. Moreover, Ameren has failed to justify revising the definition of ''transmission peak.'' While peak load data ultimately resides with the RTO or ISO, each transmission provider coordinates this type of data with RTO or ISO. Finally, we reaffirm that long-term firm service is service with a term of one year or more. Modifying the term of long-term service to reduce the number of contracts used in the denominator for purposes of calculating the load ratio share and for ratemaking purposes may affect how the transmission provider plans its system to service customers and has not been justified.

E. Enforcement

1714. The Commission attaches substantial importance to strengthening compliance with the OATT, on monitoring and auditing OATT compliance, including its staff's efforts to resolve disputes about compliance through the Enforcement Hotline and other dispute resolution mechanisms, and on investigating potential and alleged OATT violations. The expansion of the Commission's enforcement powers pursuant to EPAct 2005 directly augmented its ability to enforce the OATT by, among other things, providing authority to assess civil penalties of up to $1 million for each day that an OATT violation continues. The Commission intends to use its enforcement powers with respect to the OATT in a fair and even-handed manner, pursuant to the principles set forth in the Policy Statement on Enforcement.

1. General Policy

a. Compliance Review Regime

NOPR Proposal

1715. The Commission proposed to maintain a strong program to audit compliance with the new *pro forma* OATT. The audit program would include operational audits similar to past OATT compliance audits, during which staff may collect information on implementation of a transmission provider's OATT. The Commission stated that it would issue public reports of audit results and noted that contested audits would be subject to the Commission's Final Rule on contested operational audits.[966]

Comments

1716. Most initial commenters support a strong staff audit program.[967] Other commenters counter that staff audits will not be needed if the Commission issues a corrected *pro forma* OATT, especially with respect to RTOs and ISOs.[968] These commenters argue that formal complaints, Enforcement Hotline calls and random audits sufficiently inform staff of OATT compliance issues as to make additional staff audits unnecessary. Southern asserts that, under the separation of function policy, Commission audit staff should be separated from investigative and enforcement staff. Particular commenters contend that the Commission should focus compliance efforts on specific OATT provisions, such as those concerning network service (Arkansas Cities), or on structural issues such as independent planning and operation of transmission facilities (Reliant). Nevada Companies suggests that the Commission set up regional audit teams to foster strong working relationships with transmission providers. EPSA asks the Commission to adopt stronger measures than a staff audit program to monitor compliance. EPSA's proposed measures include requiring transmission providers to: designate compliance officers to report OATT violations to company boards; undergo compliance audits by an

[964] Redirect-related issues are addressed in section V.D.4.

[965] *See* Order No. 888 at 31,753–54; Order No. 888–A at 30,304–5; *see also Sierra Pacific Power Co.*, 81 FERC ¶ 61,136 at 61,139–40 (1997); *New England Power Pool*, 83 FERC ¶ 61,045 at 61,248 (1998).

[966] *See Procedures for Disposition of Contested Audit Matters*, Order No. 675, 71 FR 9698 (Feb. 27, 2006), FERC Stats. & Regs. ¶ 31,209 (2006) (Contested Audit Matters), *order on rehearing and clarification*, Order No. 675–A, 71 FR 29779 (May 24, 2006), FERC Stats. & Regs. ¶ 31,217 (2006).

[967] *E.g.,* APPA, AWEA, EEI, Morgan Stanley, NRG, Southern, TAPS, and Williams.

[968] *E.g.,* Ameren, PNM–TNMP, and South Carolina E&G. In reply comments, TDU Systems urge the Commission to reject this contention.

independent auditor in response to material violations; and hire an independent administrator to oversee OATT compliance and regional planning efforts if a transmission provider has not complied with its new OATT within a specified period of time. In reply comments, MISO opposes EPSA's proposal for a third-party compliance administrator for RTOs and ISOs if they do not timely comply with new OATT provisions, arguing that these entities already are independent administrators of transmission grids and planning processes. MISO asserts that inserting an ''independent'' authority over OATT compliance by RTOs and ISO would create a superfluous bureaucratic layer. NRECA opposes EPSA's proposal because a third-party compliance administrator or auditor would be too expensive and the Commission cannot delegate its compliance authority.

1717. Noting that the Commission required RTOs to undertake extensive market monitoring in Order No. 2000, PJM states that the Commission should require in the *pro forma* OATT a similar degree of market monitoring in non-RTO areas to make available to Commission staff information needed to ascertain market abuses in these areas. PJM asserts that any such market monitoring should be performed by entities independent of the non-RTO utilities, with Commission oversight. Indicated Parties reply that RTOs' market monitors should examine market power in transmission planning because RTOs delegate transmission operations and planning duties to constituent transmission owners that retain incentives to benefit affiliates or vertically-integrated divisions.

Commission Determination

1718. The Commission adopts the NOPR proposal to emphasize a strong staff audit program for compliance with OATT requirements, including operational audits. Staff audits of OATT compliance may be random or targeted with respect to the entities being audited or particular provisions of the OATT that are scrutinized. Because its responsibility is to assess and ensure compliance with the OATT, staff will maintain discretion as to the entities it audits and the subject matter of these audits. The Commission encourages transmission providers to designate employees as compliance officers for the OATT or to conduct third-party audits relating to OATT compliance when appropriate. However, we do not believe that staff should forego an audit of an entity's OATT compliance solely because a transmission provider has designated an OATT compliance officer, engaged a third-party auditor, or transferred transmission functions to an independent transmission coordinator. We decline EPSA's proposal to require such actions, except on a case-by-case basis when warranted.

1719. We disagree with PJM's request that the Commission require third-party market monitoring to ascertain market abuses occurring with respect to transmission providers outside RTOs and ISOs, subject to Commission oversight. In a number of instances since 2000, the Commission has established third-party monitoring of a transmission provider located outside an RTO or ISO.[969] These monitors were established on a case-specific basis to address concerns related to the transmission provider at issue. We have no evidence to support requiring monitors for every transmission provider in the Nation. Further, the Commission has access to substantial information on OATT compliance by transmission providers that are not RTOs or ISOs through their postings on OASIS, informal and formal complaints by customers, and reports by market monitors for such transmission providers. Indeed, the revised *pro forma* OATT will greatly enhance our oversight and enforcement capabilities by increasing the transparency of many critical functions under the *pro forma* OATT, such as ATC calculation and transmission planning. PJM has not provided any evidence that the enhanced transparency under the OATT, coupled with the Commission's own monitoring and audits of OATT compliance and its enhanced enforcement authority, will be insufficient to ascertain and deter OATT violations. We do not object to the suggestion of Indicated Parties that RTO and ISO market monitors examine market power in transmission planning, so long as the market monitors' activities in this respect are consistent with these roles as set forth in the applicable RTO and ISO tariffs.

1720. We do not agree with Southern's assertion that the Commission's audit staff should be separated from its investigative and enforcement staff. The Commission's separation of functions regulation[970] generally permits Commission auditors, investigators and enforcement staff to speak freely to persons inside the Commission as to the subject matter of their inquiries.[971] Southern has not cited any justification for restricting communications among these staff members or from them to the Commission. To the contrary, a free flow of communications among auditors and investigators, consistent with the Commission's rule on staff separation of functions, should increase the efficiency of the Commission staff's compliance program and enforcement efforts.[972]

b. Use of Independent Third Party Audits

NOPR Proposal

1721. The Commission proposed not to mandate the use of third party auditors and, instead, proposed that Commission staff conduct audits of compliance with the *pro forma* OATT. The Commission stated that it may require third party compliance audits as part of a compliance plan following a Commission staff audit report. In response to situations such as systematic OATT violations, a pattern of repeated violations, or violations that require ongoing monitoring, the Commission could require an audited party to hire a third party to continue compliance audits.

Comments

1722. Most initial commenters agree with the Commission's proposal to require third-party audits only as part of an individual post-audit compliance plan.[973] EEI and Southwestern Coop submit that selection of third-party auditors should be subject to Commission review and approval, while South Carolina E&G cautions that the Commission should carefully weigh the costs and benefits of independent auditors before requiring their use. Southern suggests that third-party audits be required only for systematic, egregious OATT violations. Entegra doubts that third-party auditors can remedy patterns of discrimination by transmission providers against independent merchant generators.

[969] *See, e.g., Duke Power,* 113 FERC ¶ 61,288 (2005); *MidAmerican Energy Holdings Co.,* 113 FERC ¶ 61,298 (2005).

[970] 18 CFR 385.2202.

[971] *Statement of Administrative Policy on Separation of Functions,* 101 FERC ¶ 61,340 at P 24–26 (2002).

[972] *See also* Order No. 675–A at P 25–29 (the Commission's regulation and policy statement on separation of functions remain applicable following EPAct 2005, and efficiency and sound administrative practice continue to favor the sharing of information between the Commission's audit staff and investigative staff).

[973] *E.g.,* Alberta Intervenors, Arkansas Commission, Constellation, EEI, EPSA, MISO/PJM States, Nevada Companies, PNM–TNMP, South Carolina E&G, Southwestern Coop, and Suez Energy NA.

Commission Determination

1723. The Commission adopts the NOPR proposal not to require generally the use of third party auditors to assess compliance with the OATT. We believe that a requirement for the use of third-party audits in compliance plans should depend on particular facts, including the egregiousness and extent of violations found during a staff audit or investigation and the appropriate scope or cost of a third-party audit. As stated above, we encourage transmission providers to use third-party compliance audits when appropriate to supplement our staff's audit efforts.

2. Civil Penalties

1724. In the NOI, the Commission asked for comment as to whether it should address imposing remedies or penalties against transmission providers as part of OATT reform. After the NOI, the Commission issued its Policy Statement on Enforcement and, in response to specific authority granted it in EPAct 2005, issued Order No. 670, the Anti-manipulation Rule. [974]

a. Whether Civil Penalties Should Be Specified in the OATT

NOPR Proposal

1725. Aside from operational penalties proposed in the NOPR, [975] the Commission proposed not to establish a schedule of enforcement remedies and sanctions in the *pro forma* OATT. Rather, the Commission stated that it would address OATT violations and appropriate responses on a case-by-case basis, consistent with the Policy Statement on Enforcement. The Commission explained that it may impose civil penalties when warranted, after consideration of applicable factors listed in the Policy Statement on Enforcement; OATT violators also will be expected to disgorge unjust profits when they can be determined or reasonably estimated.

Comments

1726. The majority of parties filing comments on this issue agree that the Commission should assess civil penalties on a case-by-case basis under the guidance of the Policy Statement on Enforcement. [976] Other commenters instead support incorporation in the *pro forma* OATT of a schedule of significant remedies and sanctions for specific violations to assure transparency and certainty as to situations in which penalties would be assessed and to deter anticompetitive behavior. [977] EPSA advises that the Commission refrain from setting pre-determined limits on penalty amounts because each violation of a specific *pro forma* OATT provision may present different facts that may warrant different outcomes. Nevada Companies suggest that the Commission provide incentives to construct new transmission infrastructure rather than implement an overbearing penalty regime because additional transmission capacity itself will resolve many complaints.

1727. Wisconsin Electric concludes that OATT violations by non-profit RTOs and ISOs should not be subject to civil penalties because they would be passed through to customers and not act as an effective deterrent. [978] Rather than assess a penalty in response to an RTO's or ISO's OATT violation, Wisconsin Electric suggests that the Commission could intensify oversight of an RTO's or ISO's OATT compliance. NorthWestern comments, in contrast, that RTOs and ISOs should not be exempted from civil penalty assessments for their OATT violations, because these violations could have as much or more adverse effects on transmission access or system reliability as would OATT violations by other transmission providers.

1728. Several commenters support the Commission's proposal to consider mitigating factors listed in the Policy Statement on Enforcement in assessing civil penalties for OATT violations. [979] In this regard, EEI states that the Commission should clarify that when a party engages in self-reporting, compliance programs or cooperation with Commission staff, the Commission will recognize the party's attorney-client privilege. [980]

1729. EEI suggests that the Commission establish ''safe harbors'' against civil penalties for OATT violations involving reasonable interpretations of tariff provisions or for actions taken for reliability purposes that are consistent with good utility practice. PNM–TNMP and Southern ask the Commission to clarify that LSEs will not be penalized for OATT violations for taking actions necessary to meet their native load obligations since, pursuant to new FPA section 217, [981] LSEs should not be considered to have engaged in ''undue discrimination or preference'' for certain actions required to serve native load customers. TDU Systems argue in reply comments that a ''safe harbor'' approach could permit unduly discriminatory or preferential behavior that would be penalized under a case-by-case approach. Entegra replies that safe harbors for ''reasonable'' tariff interpretations would give vertically-integrated utilities license to discriminate against competitors, and suggests that the Commission ensure that the OATT operates as a sword for attacking undue discrimination, not as a shield for defending it. Occidental replies that transmission providers with a Commission-approved independent transmission coordinator should not be insulated from tariff-based civil penalties and other sanctions.

Commission Determination

1730. Following enactment in EPAct 2005 of enhanced authority for the Commission to assess civil penalties for violations of statutes it administers and of regulations and orders under these statutes, the Commission issued the Policy Statement on Enforcement to set forth how it intends to use this authority consistent with the statute. [982] Underlying this policy is the recognition that the appropriate basis for assessment of a civil penalty for a violation is an examination of the facts and circumstances relating to that violation, and the use of discretion and flexibility to address it on its merits. This examination includes a review of all applicable mitigating factors set forth in the Policy Statement on Enforcement. While we understand that establishing a schedule of civil penalties for violations of particular provisions of the *pro forma* OATT would establish greater specificity with respect to civil penalties, the Commission already concluded in the Policy Statement on Enforcement that it would ''not prescribe specific penalties or develop formulas for different violations.'' [983] We see no justification to depart from

[974] *Prohibition of Energy Market Manipulation,* III FERC Stats. & Regs. ¶ 31,202 (2006), *order denying rehearing,* 114 FERC ¶ 61,300 (2006).

[975] NOPR at P 384.

[976] *E.g.,* APPA, EEI, EPSA, Nevada Companies, PNM–TNMP, Southern, and Southwestern Coop. Southwestern Coop also urges speedy review of violations and swift assessment of penalties. In reply comments, Sacramento adds that the Commission may assess civil penalties against a transmission provider that engages in unduly discriminatory behavior in its transmission planning process.

[977] *E.g.,* Arkansas Commission and ELCON.

[978] Wisconsin Electric asserts that the Commission has recognized this principle in other contexts, *citing Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators,* FERC Stats. & Regs. ¶ 35,546 at P 9 (2004).

[979] *E.g.,* Nevada Companies and PNM–TNMP.

[980] EEI observes that the Commission held in its final rule on contested audit procedures that ''an audited person who appropriately interposes the attorney-client privilege will not be considered non-cooperative.'' Contested Audit Matters at P 35.

[981] 16 U.S.C. 824q(k).

[982] Policy Statement on Enforcement at P 1.

[983] *Id.* at P 13.

that decision with respect to violations of OATT provisions.

1731. Several commenters ask that we establish specific ''safe harbors'' or exemptions from assessment of civil penalties for OATT violations in specific circumstances or with respect to specific types of entities that may engage in OATT violations. We decline to create automatic safe harbors for specific circumstances or specific types of OATT violations. The creation of such exemptions would require us to forego the examination of the specific circumstances of particular violations that we described in the Policy Statement on Enforcement as the touchstone of our policy in assessing civil penalties. Instead, we will decide requests for leniency in particular cases by using the principles set forth in the Policy Statement on Enforcement and considering all applicable mitigating factors listed therein.[984]

1732. Likewise, we will not establish an automatic exemption from civil penalty assessments for OATT violations committed by particular types of entities such as non-profit RTOs and ISOs. The Commission decided last year that it would not automatically exempt RTOs and ISOs from penalties assessed by the Electric Reliability Organization or Regional Entities for reliability violations pursuant to new FPA section 215. In Order No. 672, the Commission stated, ''[w]hile we recognize that RTOs and ISOs have some unique characteristics, we do not believe that a generic exemption from any type of penalty is appropriate for any entity, including an RTO or ISO.'' [985] We believe the same principle applies to civil penalties for OATT violations. However, in assessing civil penalties for OATT violations, we will consider all applicable facts relating to the violator, including the effect of potential penalties on the financial viability of the violator.[986]

1733. We agree with commenters who state that the Commission and its staff should recognize the valid assertion of the attorney-client privilege in the context of investigations, audits and other fact-finding activities. As EEI points out, we recently stated with respect to audits that we would not consider an entity to be uncooperative with audit staff if the entity appropriately asserts that a communication or document is covered by that privilege.[987] We take the same position with respect to investigations or other fact-finding undertakings with respect to possible OATT violations.

1734. In the Policy Statement on Enforcement, however, the Commission drew a distinction between cooperation, which we expect from entities subject to the Commission's jurisdiction given their statutory obligation to provide information to us, and ''exemplary'' cooperation, which ''quickly ends wrongful conduct, determines the facts, and corrects a problem.'' [988] The Commission explained that we will give some consideration to exemplary cooperation and indicated that one example of such cooperation is a situation in which an entity being investigated provides to staff internal investigations or audit reports relating to misconduct. These investigations and reports may include information that an entity could properly shield from disclosure pursuant to the attorney-client privilege. We observe that an entity that is in a position to assert this privilege validly also has the option to waive it. If a waiver of attorney-client privilege, whether related to an internal investigation or audit or not, assists staff in ascertaining the facts relating to alleged or apparent misconduct, ends misconduct quickly or otherwise substantially advances an investigation or inquiry, that waiver may be an element in finding ''exemplary cooperation'' as described in the Policy Statement on Enforcement.[989]

b. Whether Transmission Providers Should Be Subject to Revocation of Market-Based Rates for OATT Violations

NOPR Proposal

1735. The Commission observed in the NOPR that some OATT violations, after applying the factors in the Policy Statement on Enforcement to all facts and circumstances, may merit revocation of market-based rate authority. Before considering revoking an entity's market-based rate authority for an OATT violation, the Commission proposed that it must find a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority. The Commission also proposed that if it determines, as a result of a significant OATT violation, to revoke the market-based rate authority of a transmission provider within a particular market, each affiliate of the transmission provider that possesses market-based rate authority would have that authority revoked in that market, effective on the date of revocation of the transmission provider's market-based rate authority.

Comments

1736. Most parties that submitted initial comments on this issue support the Commission's conclusion that, in certain circumstances, it may be appropriate to revoke the market-based rate authority of an entity that engages in an OATT violation.[990] The majority of these commenters support the Commission's proposal to do so only if it finds a nexus between the OATT violation and the entity's market-based rate authority.[991]

1737. Some commenters oppose the requirement for a nexus between the OATT violation and the entity's market-based rate authority because the Commission has not stated what facts would be sufficient to show such a nexus.[992] EPSA and NRECA (in reply comments) contend that if the Commission does not remove the ''nexus'' condition, it should clarify what constitutes a ''nexus'' between an OATT violation and an entity's market-based rate authority. Similarly, PNM–TNMP argues that such a nexus must be clear and fact-specific, consistent with the Policy Statement on Enforcement. TDU Systems contend in reply

[984] We have also provided clarification on the procedures that would apply to the assessment in formal proceedings of civil penalties relating to OATT violations in our recent *Statement of Administrative Policy Regarding the Process for Assessing Civil Penalties,* 117 FERC ¶ 61,317 (2006).

[985] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 at P 634 (2006), *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[986] Policy Statement on Enforcement at P 20. *Cf.* Order No. 672–A at P 56–57 (holding that for determining a penalty pursuant to the FPA section 215 reliability program, circumstances such as organization structure or non-for-profit status will be considered, but that there should not be an automatic exemption from monetary penalties for RTOs and ISOs).

[987] *Citing* Contested Audit Matters at P 35.

[988] Policy Statement on Enforcement at P 26.

[989] *See In re PacifiCorp,* 118 FERC ¶ 61,026 at P 3, 8 and attached stipulation and consent agreement at P 24 (2007) (referring to transmission provider's waivers of attorney-client privilege as an element in making finding of exemplary cooperation with investigation when approving settlement assessing civil penalty that resolved a transmission provider's violations of its OATT, among other matters); *In re Entergy Services, Inc.,* 118 FERC ¶ 61,027 at P 15, 18 (2007) (same).

[990] *E.g.*, EEI, ELCON, Morgan Stanley, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, Southern, and TDU Systems.

[991] *E.g.*, EEI, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, and Southern.

[992] *E.g.*, APPA.

comments that, at a minimum, a transmission provider or its affiliate that has market-based rate authority must overcome a rebuttable presumption that its OATT violation has the requisite ''nexus'' to support revocation of such authority.

1738. Other commenters argue that a serious OATT violation removes the mitigation of transmission market power provided by adherence to an OATT, thereby eviscerating one of the essential requirements for market-based rate authority.[993] EEI and PNM–TNMP reply that not every OATT violation diminishes the availability of transmission service so as to establish vertical market power.

1739. APPA and TDU Systems suggest in reply comments that the proposed nexus condition would unduly limit any sanctions, because the shareholders of the violator could still reap the benefits of such a violation if an affiliate that did not have any knowledge of the OATT violation could continue to engage in transactions under market-based rate authority. According to APPA, this possibility could lessen the incentive for senior management over a transmission provider and affiliates to make OATT compliance a high priority. As such, APPA and TAPS suggest that the Commission consider revoking a transmission provider's market-based rate authority for a ''material'' OATT violation that effectively denies, delays, or diminishes a customer's access to transmission service essential to mitigating transmission market power.

1740. TDU Systems caution that revocation of market-based rate authority may not be sufficient to deter OATT violations if reversion to cost-based rates may provide a transmission provider with the ability to recover all costs and receive higher revenues than competitive markets might otherwise produce. Therefore, TDU Systems ask that the Commission consider assessment of civil penalties in addition to revocation of market-based rate authority.

1741. The majority of commenters disagree, however, with the Commission's proposal to revoke the market-based rate authority of all affiliates of a transmission provider to the same extent that we revoke that transmission provider's market-based rate authority.[994] These commenters assert that affiliates that have no knowledge of, or involvement in, their affiliated transmission provider's unlawful activities should not lose their market-based rate authority as a result of the transmission provider's OATT violation. NRECA replies that market-based rate authority is a privilege, not a right, and asserts that the Commission should revoke market-based rate authority in response to an OATT violation that indicates that a public utility possesses market power.

1742. APPA also suggests that, short of revocation of a transmission provider's market-based rate authority in response to an OATT violation, the Commission could condition that authority, or the market-based rate authority of the transmission provider's affiliates. APPA provides the following examples of such conditions: A requirement to participate in joint planning of transmission facilities with the transmission provider's network customers and offer these customers appropriate credits under OATT section 30.9; an offer of joint transmission ownership opportunities to LSEs for new transmission facilities on reasonable terms and conditions; and an offer to network service customers to participate in the ownership of the transmission provider's existing transmission system on a load ratio share basis.

Commission Determination

1743. We adopt the NOPR proposal to revoke an entity's market-based rate authority in response to an OATT violation only upon a finding of a specific factual nexus between the violation and the entity's market-based rate authority. We believe that the ''nexus condition'' is required in order to ensure that our actions are not arbitrary or capricious or based on an inadequate factual record. We note that in this context the Commission has the burden to show a factual nexus. We do not assign a burden on the violator to show the lack of this nexus.

1744. Determining what would be a sufficient factual nexus between an OATT violation and revocation of the violator's market-based rate authority is best left to a case-by-case consideration. The wide range of positions among commenters on how to define a sufficient factual nexus itself suggests that this finding is best made after review of a specific factual situation. Some commenters assert that a finding of a ''serious'' or ''material'' violation of the OATT would be sufficient. We disagree. While an entity's inconsequential OATT violation would not serve as a basis for revoking that entity's market-based rate authority, our view is that the nexus condition requires us to find both that a substantial OATT violation has occurred and that the violation either related to the exercise of the violator's market-based rate authority or violated a specific condition of that authority.

1745. The Commission emphasizes that we have discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances in which we do not find a factual nexus justifying revocation of that authority. For example, in appropriate circumstances, we may modify or add additional conditions to the violator's market-based rate authority or impose other requirements to help ensure that the violator does not commit future, similar misconduct. Nor is revocation of market-based rate authority the only action we may take to respond to an OATT violation that meets the nexus condition. We will consider whether to impose sanctions such as assessment of civil penalties for particularly serious OATT violations in addition to revocation of the violator's market-based rate authority.

1746. We do not adopt our proposal from the NOPR to revoke the market-based rate authority of each affiliate of a transmission provider that loses its market-based rate authority within a particular market as a result of an OATT violation. Rather, we will create a rebuttable presumption that all affiliates of a transmission provider should lose their market-based rate authority in each market in which their affiliated transmission provider loses its market-based rate authority as a result of an OATT violation. We will allow an affiliate of a transmission provider to retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption with respect to that market area.

1747. We expect that the issue of potential revocation of market-based rate authority will arise as a result of an OATT violation in a market in which the transmission provider possesses transmission market power through the ownership of transmission facilities in that market. For these markets, we have evaluated whether a transmission provider should receive authority to make sales of electric power for resale at market-based rates using a four-prong analysis. In this analysis we consider whether the transmission provider and its affiliates have adequately mitigated market power in generation and transmission, whether the transmission provider or its affiliates can erect other barriers to entry, and whether there is evidence that the transmission provider and its affiliates have engaged in

[993] *E.g.*, APPA, EPSA, and TAPS.

[994] *E.g.*, EEI, Nevada Companies, Northwest IOUs, Progress Energy, PNM–TNMP, Sempra Global, and Southern.

affiliate abuse or reciprocal dealing.[995] In particular, we have long held that the existence of an OATT is deemed to mitigate vertical market power and transmission market power held by a transmission provider and its affiliates in a particular market. An OATT violation by a transmission provider in a market in which it possesses transmission market power that merits revocation of the transmission provider's market-based rate authority may call into question whether the transmission provider's affiliates continue to qualify for market-based rates in that market under the standards that we have established.[996] As a result, we believe that it is appropriate to establish a presumption in this circumstance that if we find that a transmission provider should lose its market-based rate authority in a market in which it possesses transmission market power, we will revoke the market-based rate authority in that market of all affiliates of the transmission provider.

1748. We are mindful, however, that the circumstances of a particular affiliate may not always justify the imposition of a remedy so severe as revocation of market-based rate authority in a particular market when its affiliated transmission provider loses its market-based rate authority in that market as a result of an OATT violation. To afford due process to a transmission provider's affiliates in that situation, and to ensure that a determination to revoke market-based rate authority in a particular market for a transmission provider and all of its affiliates that possess such authority is adequately based upon record evidence and not arbitrary or capricious, we will allow an opportunity for each such affiliate to make a showing that it should retain its market-based rate authority or that enforcement action against it should be less severe than revocation. The determination whether an affiliate has overcome the rebuttable presumption depends on an analysis of specific facts in the record. Relevant facts would include, but are not limited to, whether: (1) The transmission provider and the affiliate were under the same control; (2) the affiliate knew of, participated in or was an accomplice to the OATT violation; (3) the affiliate assisted the transmission provider in exercising market power; or (4) the affiliate benefited from the violation.

c. Whether Certain OATT Violations Should Be Considered Market Manipulation Under Section 222 of the FPA

NOPR Proposal

1749. The Commission proposed in the NOPR to decline to identify in the *pro forma* OATT specific conduct that constitutes *per se* market manipulation. The Commission proposed to consider on a case-by-case basis, if and when they arise, whether specific circumstances relating to OATT violations constitute market manipulation under the standards set forth in Order No. 670.

Comments

1750. All commenters on this issue concur with a case-by-case approach to it.[997] Southwestern Coop suggests that, as the Commission gains sufficient experience to describe particular misconduct as market manipulation *per se,* it should identify such misconduct in the OATT. While contending that the Commission should act with caution in listing behaviors that constitute *per se* market manipulation in view of the dynamic nature of markets, TDU Systems urge the Commission to specify in the OATT that transmission planning misconduct could constitute a form of market manipulation or abuse.

Commission Determination

1751. We adopt the NOPR proposal for a case-by case approach to considering whether OATT violations may constitute market manipulation. Without reference to a specific factual pattern developed in an investigation or on-the-record proceeding, the Commission is not in a position to identify market manipulation relating to OATT violations.[998]

VI. Information Collection Statement

1752. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting, record keeping, and public disclosure (collections of information) imposed by an agency.[999] Pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB for review under section 3507(d) of the Paperwork Reduction Act of 1995.[1000]

1753. The Commission identifies the information provided under Part 35 subpart C as contained in FERC–516 and Part 37 as contained in FERC–717. The Commission solicited comments on the need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information exchanges. The Commission did not receive any specific comments regarding its burden estimates. Where commenters raised concerns that specific information collection requirements would be burdensome to implement, the

[995] In our recent NOPR on market-based rates for wholesale sales of electricity, the Commission proposed to discontinue referring to affiliate abuse among a transmission provider and its affiliates as a separate ''prong'' of our analysis of whether to grant market-base rate authority. The Commission instead proposed to address affiliate abuse by requiring that transmission providers and their affiliates comply with restrictions and conditions set forth in the regulations we propose in that proceeding. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 at P 13 (2006).

[996] We observe that specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations have involved transactions with affiliates. *See Idaho Power* (settlement of, among other issues, an Enforcement staff allegation that a transmission provider permitted its merchant function to request non-firm transmission to enable the merchant function to make off-system sales that by definition were not used to serve native load, so that the transmission did not qualify for the ''native load'' priority specified in section 28.4 of the transmission provider's OATT); *Cleco Corp.*, 104 FERC ¶ 61,125 (2003) (settlement between Enforcement staff and a utility holding company and its subsidiaries relating, in part, to the provision by a transmission provider of a unique type of transmission service that was neither made available to non-affiliates nor included in its FERC tariff); *Tucson Electric Power Co.*, 109 FERC ¶ 61,272 (2004) (operational audit in which staff found that, among other matters, a transmission provider permitted its wholesale merchant function to purchase hourly non-firm and monthly firm point-to-point transmission service using an off-OASIS scheduling procedure while the transmission provider did not post on its OASIS the availability of capacity on these paths); *South Carolina Electric & Gas Co.*, 111 FERC ¶ 61,217 (2005) (settlement of Enforcement staff allegation that a transmission provider made available firm point-to-point transmission service to its affiliated merchant function that did not submit transmission schedules with specific receipt points for the service as required by section 13.8 of the transmission provider's OATT); and *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005) (operational audit in which staff found, among other things, that a transmission provider permitted its wholesale merchant function to (a) use network transmission service to bring short-term energy purchases onto its system while it simultaneously made off-system sales, inconsistently with the preamble to Part III of the transmission provider's OATT and section 28.6 of its OATT; and (b) confirm firm network transmission service requests without identifying a designated network resource or acquiring an associated network resource, in some instances using this service to deliver short-term energy purchases used to facilitate off-system sales, inconsistent with section 29.2 or section 30.6 of the transmission provider's OATT). *See also* Commission orders cited in note 989 *supra*.

[997] APPA, Nevada Companies, PNM–TNMP, Southwestern Coop, and TDU Systems.

[998] Similarly, in issuing the *Anti-manipulation Rule*, we declined to provide specific examples of what would constitute market manipulation. Order No. 670 at P 64–67.

[999] 5 CFR 1320.11.

[1000] 44 U.S.C. 3507(d).

Commission has address those concerns elsewhere in the rule.

1754. The Commission estimates the burden for complying with the Final Rule is as follows: [1001]

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
Part 35 (FERC–516)				
Conforming tariff changes	116	1	25	2,900
Revision of Imbalance Charges	116	1	5	580
ATC revisions	116	1	40	4,640
Planning (Attachment K)	116	1	200	23,200
Congestion studies	116	1	300	34,800
Attestation of network resource commitment	116	1	1	116
Capacity reassignment	116	1	100	11,600
Operational Penalty annual filing	116	1	10	1,160
Creditworthiness—include criteria in the tariff	116	1	40	4,640
Sub Total Part 35				83,636
Part 37 (FERC–717)				
ATC-related standards:				
NERC/NAESB Team to develop	1	1	1,920	1,920
Review and comment by utility	116	1	20	2,320
Implementation by each utility	116	1	40	4,640
Mandatory data exchanges	116	1	80	9,280
Explanation of change of ATC values	116	1	100	11,600
Reevaluate CBM and post quarterly	116	1	20	2,320
Post OASIS metrics; requests accepted/denied	116	1	90	10,440
Post planning redispatch offers and reliability redispatch data	116	1	20	2,320
Post curtailment data	116	1	10	11,160
Post Planning and System Impact Studies	116	1	5	580
Posting of metrics for System Impact Studies	116	1	100	11,600
Post all rules to OASIS	116	1	5	580
Sub Total (Part 37)				68,760
Total (Part 35 + Part 37)				140,476
Recordkeeping	116	1	40	4,640

1755. *Information Collection Costs:* No comments were received regarding the Commission's estimate of costs to comply with these requirements. The Commission has projected costs of compliance as follows:

Total Annual Hours for Collection:

Reporting + recordkeeping hours = 152,396 + 4,640 = 157,036 hours.

Cost to Comply:

Reporting = $17,373,144

152,396 hours @ $114 an hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25))

Recordkeeping = $7,478,888

Labor (file/record clerk @ $17 an hour) 4,640 hours @ $17/hour = $78,880

Storage 8,000 sq. ft. × $925 (off site storage) = $7,400,000

Total costs = $24,852,024

Labor $ ($17,373,144 + $78,880) + Recordkeeping Storage Costs ($7,400,000)

Title: FERC–516, Electric Rate Schedules and Tariff Filings; FERC–717 Standards for Business Practices and Communication Protocols for Public Utilities.

Action: Proposed Collections.

OMB Control Nos. 1902–0096 and 1902–0173.

Respondents: Business or other for profit.

Frequency of responses: On occasion.

Necessity of the Information: The Federal Energy Regulatory Commission adopts these amendments to its regulations adopted in Order Nos. 888 and 889, and to the *pro forma* open access transmission tariff, to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose—remedying undue discrimination—not to create new market structures. We propose to achieve this goal by increasing the clarity and transparency of the rules applicable to the planning and use of the transmission system and by addressing ambiguities and the lack of sufficient detail in several important areas of the *pro forma* OATT. The lack of specificity in the *pro forma* OATT creates opportunities for undue discrimination as well as making the undue discrimination that does occur more difficult to detect. To accomplish this we are proposing five objectives: (1) To improve transparency and consistency in several critical areas, by providing for greater consistency in the calculation of ATC, (2) to reform the transmission planning requirements of the *pro forma* OATT to eliminate potential undue discrimination and support the construction of adequate transmission facilities to meet the needs of all LSEs, (3) to remedy certain portions of the *pro forma* OATT that may have permitted utilities to

[1001] These burden estimates applied only to the Final Rule and do not reflect upon all of FERC–516 or FERC–717.

discriminate against new merchant generation, including intermittent generation, (4) to provide for greater transparency in the provision of transmission service to allow transmission customers better access to information to make their resource procurement and investment decisions, as well as to increase the Commission's ability to detect any remaining incidents of undue discrimination; and (5) to reform and provide greater clarity in areas that have generated recurring disputes over the past 10 years, such as rollover rights, ''redirects,'' and generation redispatch. The reforms proposed in this Final Rule are intended to address deficiencies in the *pro forma* OATT that have become apparent since the implementation of Order No. 888 in 1996 and to facilitate improved planning and operation of transmission facilities.

1756. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov*.

1757. For submitting comments concerning the collections of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503 Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–3122, fax: (202) 395–7285. Due to security concerns, comments should be sent electronically to the following e-mail address: *oira_submission@omb.eop.gov*. Please reference the docket number of this rulemaking in your submission.

VII. Environmental Analysis

1758. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[1002] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications and services.[1003]

VIII. Regulatory Flexibility Act Analysis

1759. The Regulatory Flexibility Act of 1980 (RFA)[1004] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888 and 889. The total number of public utilities that, absent waiver, would have to modify their current OATTs by filing the revised pro forma OATT is 116.[1005] Of these only six public utilities, or less than two percent, have output of four million MWh or less per year.[1006] The Commission does not consider this a substantial number and, in any event, each of these entities retains its rights to waiver of these requirements.[1007] The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888 and 889. Accordingly, the Commission certifies that the Final Rule will not have a significant economic impact on a substantial number of small entities.

IX. Document Availability

1760. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

1761. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type ''RM05–25'' or ''RM05–17'' in the docket number field.

1762. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance, please contact the Commission's Online Support at 1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

X. Effective Date and Congressional Notification

1763. These regulations are effective May 14, 2007. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and to the General Accounting Office.

List of Subjects

18 CFR Part 35

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

18 CFR Part 37

Conflict of interests, Electric power plants, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Magalie R. Salas,

Secretary.

■ In consideration of the foregoing, the Commission amends parts 35 and 37,

[1002] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[1003] 18 CFR 380.4(a)(15).

[1004] 5 U.S.C. 601–612.

[1005] The Commission has identified 116 transmission providers with tariffs on file. We note that this figure is lower than our initial estimate in the NOPR, based on FERC Form No. 1 and FERC Form No. 1–F data.

[1006] *Id.*

[1007] The Regulatory Flexibility Act defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6); 15 U.S.C. 632(a)(1). In *Mid-Tex Elec. Coop.* v. *FERC*, 773 F.2d 327, 340–43 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The revised *pro forma* OATT will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

Chapter I, Title 18 of the *Code of Federal Regulations*, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

■ 2. Amend § 35.28 as follows:
■ a. Paragraph (c) is revised.
■ b. Paragraphs (d)(i) and (d)(ii) are redesignated as paragraphs (d)(1) and (d)(2).
■ c. Newly redesignated paragraph (d)(1) is revised.
■ d. Paragraph (e)(1) introductory text is revised.
■ e. Paragraph (e)(1)(ii) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.* (1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs ¶ 31,306 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of May 14, 2007, it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce as of May 14, 2007, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than May 14, 2007 the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the pro forma tariff required by this section.

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved.]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after May 14, 2007, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs ¶ 31,241.

(d) *Waivers.* * * *

(1) No later than May 14, 2007, or

* * * * *

(e) *Non-public utility procedures for tariff reciprocity compliance.* (1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036 and Order No. 890, FERC Stats. & Regs. ¶ 31,241.

* * * * *

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 or 211A order should be granted.

* * * * *

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS

■ 3. The authority citation for part 37 continues to read as follows:

Authority: 16 U.S.C. 791–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 4. Amend § 37.6 as follows:
■ a. Paragraph (a)(1) is revised.
■ b. Paragraph (b) introductory text is revised.
■ c. Paragraphs (b)(1)(v) through (b)(1)(viii) are added.
■ d. Paragraphs (b)(2)(i) through (b)(2)(iii) are revised.
■ e. Paragraph (b)(3) is revised.
■ f. Paragraphs (c)(2) and (c)(5) are revised.
■ g. Paragraphs (e)(1) and (e)(2)(ii) are revised.
■ h. Paragraph (e)(3)(ii) is revised.
■ i. Paragraphs (h), (i) and (j) are added.

§ 37.6 Information to be posted on the OASIS.

(a) * * *

(1) Make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services, request the designation of a network resource, and request the termination of the designation of a network resource;

* * * * *

(b) *Posting transfer capability.* The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

(1) * * *

(v) *Available transfer capability* or *ATC* means the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses, or such definition as contained in Commission-approved Reliability Standards.

(vi) *Total transfer capability* or *TTC* means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.

(vii) *Capacity Benefit Margin* or *CBM* means the amount of TTC preserved by the Transmission Provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Commission-approved Reliability Standards.

(viii) *Transmission Reliability Margin* or *TRM* means the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Commission-approved Reliability Standards.

(2) * * *

(i) Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Commission-approved Reliability Standards as well as current industry practices, standards and criteria.

(ii) On request, the Responsible Party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (*e.g.*, thermal, voltage, stability), as well as load forecast assumptions) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

(iii) System planning studies, facilities studies, and specific network impact studies performed for customers or the Transmission Provider's own network resources are to be made publicly available in electronic form on request and a list of such studies shall be posted on the OASIS. A study is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. These studies are to be retained for five years.

(3) *Posting.* The ATC, TTC, CBM, and TRM for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

(i) *Constrained posted paths.*—(A) *For firm ATC and TTC.*

(*1*) The posting shall show ATC, TTC, CBM, and TRM for a 30-day period. For this period postings shall be: by the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted daily for each period.

(*2*) Postings shall also be made by the month, showing for the current month and the 12 months next following.

(*3*) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

(B) *For non-firm ATC and TTC.* The posting shall show ATC, TTC, CBM and TRM for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(*1*) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A) (*2*) and (*3*) of this section. The posting of non-firm ATC and TTC shall show CBM as zero.

(C) *Updating posted information for constrained paths.*

(*1*) The capability posted under paragraphs (b)(3)(i)(A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the estimate for the path changes by more than 10 percent.

(*2*) All updating of hourly information shall be made on the hour.

(*3*) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section are updated because of a change in TTC by more than 10 percent, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the update. This narrative should include, the specific events which gave rise to the update (*e.g.*, scheduling of planned outages and occurrence of forced transmission outages, de-ratings of transmission facilities, scheduling of planned generation outages and occurrence of forced generation outages, changes in load forecast, changes in new facilities' in-service dates, or other events or assumption changes) and new values for ATC on the path (as opposed to all points on the network).

(*4*) When the monthly and yearly capability posted under paragraphs (b)(3)(i)(A) and (B) of this section remain unchanged at a value of zero for a period of six months, the Transmission Provider shall post a brief, but specific, narrative explanation of the reason for the unavailability of ATC.

(ii) *Unconstrained posted paths.*

(A) Postings of firm and nonfirm ATC, TTC, CBM, and TRM shall be posted separately by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC, TTC, CBM, and TRM will be posted separately for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

(B) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

(iii) *Calculation of CBM.*

(A) The Transmission Provider must reevaluate its CBM needs at least every year.

(B) The Transmission Provider must post its practices for reevaluating its CBM needs.

(iv) *Daily load.* The Transmission Provider must post on a daily basis, its actual daily peak load for the prior day.

(c) * * *

(2) Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff that is filed with the Commission. Transmission Providers also must provide a link to all of the rules, standards and practices that relate to transmission services posted on the Transmission Providers' public Web sites.

* * * * *

(5) Customers choosing to use the OASIS to offer for resale transmission capacity they have purchased must post relevant information to the same OASIS as used by the Transmission Provider from whom the Reseller purchased the transmission capacity. This information must be posted on the same display page, using the same tables, as similar capability being sold by the Transmission Provider, and the information must be contained in the same downloadable files as the Transmission Provider's own available capability.

* * * * *

(e) *Posting specific transmission and ancillary service requests and responses.*

(1) *General rules.*

(i) All requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, and all requests to designate or terminate a network resource, must be made on the OASIS and posted prior to the Transmission Provider responding to the request, except as discussed in paragraphs (e)(1)(ii) and (iii) of this section. The Transmission Provider must post all requests for transmission service, for ancillary service, and for the designation or termination of a network resource comparably. Requests for transmission service, ancillary service, and to designate and terminate a network resource, as well as the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff, the Federal Power Act, and Commission regulations.

(ii) The requirement in paragraph (e)(1)(i) of this section, to post requests for transmission and ancillary service offered by Transmission Providers under the *pro forma* tariff, including requests for discounts, prior to the Transmission Provider responding to the request, does not apply to requests for next-hour service made during Phase I.

(iii) In the event that a discount is being requested for ancillary services that are not in support of basic transmission service provided by the Transmission Provider, such request need not be posted on the OASIS.

(iv) In processing a request for transmission or ancillary service, the Responsible Party shall post the same information as required in paragraphs (c)(4) and (d)(3) of this section, and the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn). In processing a request to designate or terminate the designation of a network resource, the Responsible Party shall post the date and time when the request is made.

(v) For any request to designate or terminate a network resource, the Transmission Provider (at the time when the request is received), must post on the OASIS (and make available for download) information describing the request (including: name of requestor, identification of the resource, effective time for the designation or termination, identification of whether the transaction involves the Transmission Provider's wholesale merchant function or any affiliate; and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7.

(vi) The Transmission Provider shall post a list of its current designated network resources and all network customers' current designated network resources on OASIS. The list of network resources should include the name of the resource, its geographic and electrical location, its total installed capacity, and the amount of capacity to be designated as a network resource.

(2) * * *

(ii) Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for five years and provided, upon request, to the potential Transmission Customer and the Commission's Staff.

* * * * *

(3) * * *

(ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it, for five years.

* * * * *

(h) *Posting information summarizing the time to complete transmission service request studies.* (1) For each calendar quarter, the Responsible Party must post the set of measures detailed in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section related to the Responsible Party's processing of transmission service request system impact studies and facilities studies. The Responsible Party must calculate and post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates. The Responsible Party is required to include in the calculations of the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section all studies the Responsible Party conducts of transmission service requests on another Transmission Provider's OASIS.

(i) *Process time from initial service request to offer of system impact study agreement.*

(A) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new system impact study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party received the request for transmission service,

(C) Mean time (in days), for all requests acted on by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to when the Responsible Party changed the transmission service request status to indicate that the Responsible Party could offer transmission service or needed to perform a system impact study,

(D) Mean time (in days), for all system impact study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the request for transmission service to the date when the Responsible Party delivered a system impact study agreement, and

(E) Number of new system impact study agreements executed during the reporting quarter.

(ii) *System impact study processing time.*

(A) Number of system impact studies completed by the Responsible Party during the reporting quarter,

(B) Number of system impact studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed system impact study agreement,

(C) For all system impact studies completed more than 60 days after receipt of an executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data),

(D) Mean time (in days), for all system impact studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed system impact study agreement to the date when the Responsible Party provided the system impact study to the entity who executed the system impact study agreement, and

(E) Mean cost of system impact studies completed by the Responsible Party during the reporting quarter.

(iii) *Transmission service requests withdrawn from the system impact study queue.*

(A) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter more than 60 days after the Responsible Party received the executed system impact study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's system impact study queue during the reporting quarter, from the date the Responsible Party received the executed system impact study agreement to date when request was withdrawn from the Responsible Party's system impact study queue.

(iv) *Process time from completed system impact study to offer of facilities study.*

(A) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service,

(B) Number of new facilities study agreements delivered during the reporting quarter to entities that request transmission service more than thirty (30) days after the Responsible Party completed the system impact study,

(C) Mean time (in days), for all facilities study agreements delivered by the Responsible Party during the reporting quarter, from the date when the Responsible Party completed the system impact study to the date when the Responsible Party delivered a facilities study agreement, and

(D) Number of new facilities study agreements executed during the reporting quarter.

(v) *Facilities study processing time.*

(A) Number of facilities studies completed by the Responsible Party during the reporting quarter,

(B) Number of facilities studies completed by the Responsible Party during the reporting quarter more than 60 days after the Responsible Party received an executed facilities study agreement,

(C) For all facilities studies completed more than 60 days after receipt of an executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (*e.g.*, delays in providing needed data),

(D) Mean time (in days), for all facilities studies completed by the Responsible Party during the reporting quarter, from the date when the Responsible Party received the executed facilities study agreement to the date when the Responsible Party provided the facilities study to the entity who executed the facilities study agreement,

(E) Mean cost of facilities studies completed by the Responsible Party during the reporting quarter, and

(F) Mean cost of upgrades recommended in facilities studies completed during the reporting quarter.

(vi) *Service requests withdrawn from facilities study queue.*

(A) Number of transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter,

(B) Number of transmission service requests withdrawn from the

Responsible Party's facilities study queue during the reporting quarter more than 60 days after the Responsible Party received the executed facilities study agreement, and

(C) Mean time (in days), for all transmission service requests withdrawn from the Responsible Party's facilities study queue during the reporting quarter, from the date the Responsible Party received the executed facilities study agreement to date when request was withdrawn from the Responsible Party's facilities study queue.

(2) The Responsible Party is required to post the measures in paragraph (h)(1)(i) through paragraph (h)(1)(vi) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for three calendar years.

(3) The Responsible Party will be required to post on OASIS the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section in the event the Responsible Party, for two consecutive calendar quarters, completes more than twenty (20) percent of the studies associated with requests for transmission service from entities that are not Affiliates of the Responsible Party more than sixty (60) days after the Responsible Party delivers the appropriate study agreement. The Responsible Party will have to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section until it processes at least ninety (90) percent of all studies within 60 days after it has received the appropriate executed study agreement. For the purposes of calculating the percent of studies completed more than sixty (60) days after the Responsible Party delivers the appropriate study agreement, the Responsible Party should aggregate all system impact studies and facilities studies that it completes during the reporting quarter. The Responsible Party must calculate and post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section separately for requests for short-term firm point-to-point transmission service, long-term firm point-to-point transmission service, and requests to designate a new network resource and must be calculated and posted separately for transmission service requests from Affiliates and transmission service requests from Transmission Customers who are not Affiliates.

(i) Mean, across all system impact studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per system impact study the Responsible Party completes during reporting period;

(ii) Mean, across all facilities studies the Responsible Party completes during the reporting quarter, of the employee-hours expended per facilities study the Responsible Party completes during reporting period;

(iii) The number of employees the Responsible Party has assigned to process system impact studies;

(iv) The number of employees the Responsible Party has assigned to process facilities studies.

(4) The Responsible Party is required to post the measures in paragraph (h)(3)(i) through paragraph (h)(3)(iv) of this section for each calendar quarter within 15 days of the end of the calendar quarter. The Responsible Party will keep the quarterly measures posted on OASIS for five calendar years.

(i) *Posting data related to grants and denials of service.* The Responsible Party is required to post data each month listing, by path or flowgate, the number of transmission service requests that have been accepted and the number of transmission service requests that have been denied during the prior month. This posting must distinguish between the length of the service request (*e.g.*, short-term or long-term requests) and between the type of service requested (*e.g.*, firm point-to-point, non-firm point-to-point or network service). The posted data must show:

(1) The number of non-Affiliate requests for transmission service that have been rejected,

(2) The total number of non-Affiliate requests for transmission service that have been made,

(3) The number of Affiliate requests for transmission service that have been rejected, and

(4) The total number of Affiliate requests for transmission service that have been made.

(j) *Posting redispatch data.*

(1) The Transmission Provider must allow the posting on OASIS of any third party offer to relieve a specified congested transmission facility.

(2) The Transmission Provider must post on OASIS (i) its monthly average cost of planning and reliability redispatch, for which it invoices customers, at each internal transmission facility or interface over which it provides redispatch service and (ii) a high and low redispatch cost for the month for each of these same transmission facilities. The transmission provider must post this data on OASIS as soon as practical after the end of each month, but no later than when it sends invoices to transmission customers for redispatch-related services.

■ 5. In § 37.7, paragraph (b) is revised to read as follows:

§ 37.7 Auditing Transmission Service Information.

* * * * *

(b) Audit data must remain available for download on the OASIS for 90 days, except ATC/TTC postings that must remain available for download on the OASIS for 20 days. The audit data are to be retained and made available upon request for download for five years from the date when they are first posted in the same electronic form as used when they originally were posted on the OASIS.

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

Appendix A: Summary of Compliance Filing Requirements

For a more detailed description of compliance obligations please refer to the Final Rule paragraph number. 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 Web site at the following location *http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.*

Deadline (days after publication in Federal Register)	Compliance action	Final rule paragraph No.
30	Optional Implementation FPA section 205 filings allowing transmission providers to propose previously approved variations from the *pro forma* OATT that have been affected by *pro forma* OATT Final Rule reforms to remain in effect subject to a demonstration that such variations continue to be consistent with or superior to the revised Final Rule *pro forma* OATT (non RTO/ISO transmission providers). Such optional filings must request a 90 day effective date to facilitate Commission review under section 205.	P 139

Deadline (days after publication in Federal Register)	Compliance action	Final rule paragraph No.
60	Non-ISO/RTO transmission providers submit FPA section 206 filings that contain the non-rate terms and conditions set forth in Final Rule. These filings need only contain the revised provisions adopted in the Final Rule. Transmission providers utilizing the optional Implementation FPA section 205 filing described above, need only submit 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.	P 135
75	Transmission Providers must post a ''strawman'' proposal for compliance with each of the nine planning principles adopted in the Final Rule. This may be posted on the Transmission Providers Web site or its OASIS site.	P 443
90	NERC/NAESB status report and work plan for completion of ATC related business practices and standards.	P 223
	NAESB status report and work plan for completion of OASIS functionality or uniform business practices (other than those related to ATC).	P 141
120	Transmission Providers must submit redesigned transmission charges that reflect the Capacity Benefit Margin set-aside through a limited issue section 205 rate filing as part of their initial ATC related compliance filings.	P 263
180	Submit compliance filings with Attachment C (ATC) of the *pro forma* OATT	P 140
210	ISOs and RTOs, and transmission providers located within an ISO/RTO footprint, submit FPA section 206 filings that contain the non-rate terms and conditions set forth in the Final Rule. These filings need only contain the revised provisions adopted in the Final Rule or a demonstration that previously approved variations continue to be consistent with or superior to the revised *pro forma* OATT.	P 157, P 161
210	Submit compliance filings with Attachment K (Planning) of the *pro forma* OATT or RTOs and ISOs file a demonstration that their planning processes are consistent with or superior to the planning principles in the Final Rule.	P 140, P 442
N/A	Transmission Providers must file a revised Attachment C to incorporate any changes to NERC's and NAESB's reliability and business practice standards to achieve consistency in ATC within 60 days of completion of the NERC and NAESB processes.	P 325
N/A	After the submission of FPA section 206 compliance filings, 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.	P 135

Appendix B: Commenting Party Acronyms

INITIAL COMMENTERS

Abbreviation	Initial commenters
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd., ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Alcoa	Alcoa Inc. and Alcoa Power Generating Inc.
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC.
Ameren	Ameren Services Company.
American Transmission	American Transmission Company LLC.
AMP-Ohio	American Municipal Power-Ohio, Inc.
Anaheim	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
APPA	American Public Power Association.
ARC	Alliance for Retail Choice.
Arkansas Commission	Arkansas Public Service Commission.
Arkansas Municipal	Arkansas Municipal Power Association.
AWEA	American Wind Energy Association.
Barrick	Barrick Goldstrike Mines Inc.
BART	San Francisco Bay Area Rapid Transit District.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
Bureau of Reclamation	U.S. Bureau of Reclamation.
CAC/EPUC	Cogeneration Association of California (Coalinga Cogeneration Co., Mid-Set Cogeneration Co., Kern River Cogeneration Co., Sycamore Cogeneration Co., Sargent Canyon Cogeneration Co., Salinas River Cogeneration Co., Midwest Sunset Cogeneration Co. and Watson Cogeneration Co.) and Energy Producers and Users Coalition (Aera Energy LLC, BP American, Inc., Chevron USA, Inc., ConocoPhilips Co., ExxonMobil Power and Gas Services, Inc., Shell Oil Products, US, THUMS Long Beach Co., Occidental Elk Hills, Inc., and Valero Refining Co.—California).
CAISO	California Independent System Operator Corporation.
California Commission	Public Utilities Commission of the State of California.
Calpine	Calpine Corporation.
Chandley-Hogan	John D. Chandley and William W. Hogan.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
ColumbiaGrid	ColumbiaGrid Members (Bonneville Power Administration; Avista Corp.; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; Seattle City Light; and Tacoma Power.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Constellation	Constellation Energy Group, Inc.
CREPC	Committee on Regional Electric Power Corp.
Dominion	Dominion Resources Services, Inc. (Armstrong Energy Limited Partnership, LLLP; Dominion Energy Marketing, Inc.; Elwood Energy, LLC; Fairless Energy, LLC; Pleasants Energy, LLC and Virginia Electric and Power Co. d/b/a Dominion Virginia Power).
Dow	Dow Chemical Corp.
Duke	Duke Energy Corp.
E.ON	E.ON U.S. LLC.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
Eastern North Carolina	Eastern NC Towns (Towns of Black Creek, NC; Lucama, NC; Stantonsburg, NC).
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, and American Forest & Paper Institute.
Emerald	Emerald People's Utility District.
Entegra	Entegra Power Group LLC and LS Power Associates, L.P.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina.
Fertilizer Institute	Fertilizer Institute.
FirstEnergy	FirstEnergy Service Company (First Energy Solutions; American Transmission Systems, Inc.; Jersey Central Power and Light Co.; Metropolitan Edison Co.; and Pennsylvania Electric Co.).
Flathead	Flathead Electric Cooperative.
Florida Commission	Florida Public Service Commission.
Florida Industrial Cogeneration Association	Florida Industrial Cogeneration Association.
FMPA	Florida Municipal Power Agency and Midwest Municipal Transmission Group.
Geothermal Producers	CE Generation, LLC; Ormat Technologies, Inc.; Caithness Energy, LLC; and Geothermal Energy Association.
Grant	Grant County PUD, Chelan County PUD and Pend Oreille County PUD.
Great Northern	Great Northern Power Development, L.P.
Imperial	Imperial Irrigation District.
Indianapolis Power	Indianapolis Power & Light Co.
Indicated New York Transmission Owners	Central Hudson Gas & Electric Corp.; Consolidated Edison Co. of New York, Inc.; LIPA; New York Power Authority; New York State Electric & Gas Corp.; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corp.
International Transmission	International Transmission Co. d/b/a ITC*Transmission* and Michigan Electric Transmission Co., LLC.
IRH Management	IRH Management Committee and the Schedule 20A Service Providers.
ISO New England	ISO New England, Inc. and New England Power Pool.
ISO/RTO Council	ISO/RTO Council.
Lassen	Lassen Municipal Utility District.
LDWP	City of Los Angeles Department of Water and Power.
LPPC	Large Public Power Council.
Manitoba Hydro	Manitoba Hydro.
MDEA	Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission, and Public Service Commission of Yazoo City.
MidAmerican	MidAmerican Energy Company and PacifiCorp.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Transmission Owners	Midwest ISO Transmission Owners.
MISO/PJM States	Organization of MISO States and Organization of PJM States, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NAESB	North American Energy Standards Board.
NARUC	National Association of Regulatory Utility Commissioners.
National Grid	National Grid USA.
NCEMC	North Carolina Electric Membership Corporation.
NCPA	Northern California Power Agency.
NERC	North American Electric Reliability Corporation.
Nevada Commission	Public Utilities Commission of Nevada.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
New Jersey Board	New Jersey Board of Public Utilities.
New Mexico Attorney General	New Mexico Attorney General.
New York Commission	New York State Public Service Commission.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
Newfoundland	Newfoundland and Labrador Hydro.
Newmont Mining	Newmont USA Limited, dba Newmont Mining Corp.
Northeast Utilities	Northeast Utilities Service Company (Connecticut Light and Power Co.; Western Massachusetts Electric Co.; Public Service Co. of New Hampshire; Holyoke Water Power Co.; and Holyoke Power and Electric Co.).
Northwest IOUs	Northwest Investor-Owned Utilities (Avista Corp., Portland General Electric Co., and Puget Sound Energy, Inc.).
Northwest Parties	Northwest Parties (Avista Corp., Bonneville Power Administration, PacifiCorp, PNGC Power, Portland General Electric Co., Public Power Council, Public Utility Commission of Oregon and Puget Sound Energy, Inc.).
NorthWestern	NorthWestern Corporation.
NPPD	Nebraska Public Power District.
NRECA	National Rural Electric Cooperative Association.
NRG	NRG Energy, Inc.
NYAPP	New York Association of Public Power.
Occidental	Occidental Chemical Corporation.
Oklahoma Commission	Oklahoma Corporation Commission.
Old Dominion	Old Dominion Electric Cooperative.
Oversight Resources	Oversight Resources, LLC.
PGP	Public Generating Pool and Chelan County PUD.
Pinnacle	Pinnacle West Capital Corporation; Arizona Public Service Company; and APS Energy Services Company, Inc.
PJM	PJM Interconnection, LLC.
PNM–TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPL	PPL Companies.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Co. d/b/a Progress Energy Carolinas and Florida Power Corp., d/b/a Progress Energy Florida; and Progress Ventures, Inc.).
Project for Sustainable FERC Energy Policy	Project for Sustainable FERC Energy Policy (American Wind Energy Association, Delaware Division of the Public Advocate, Environmental Law & Policy Center, Illinois Citizens Utility Board, Natural Resources Defense Council, Northwest Energy Coalition, Office of the Ohio Consumers' Counsel, Pace Energy Project, Project for Sustainable FERC Energy Policy, Renewable Northwest Project, West Wind Wires, and Wind on the Wires).
PSEG	Public Service Electric and Gas Company; PSEG Power LLC; and PSEC Energy Resources & Trade LLC (PSEG Companies).
Public Power Council	Public Power Council.
Reliant	Reliant Energy, Inc.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
San Diego G&E	San Diego Gas & Electric Company.
Santa Clara	City of Santa Clara, California d/b/a Silicon Valley Power.
Santee Cooper	South Carolina Public Service Authority.
SCE	Southern California Edison.
Seattle	City of Seattle—City Light Department.
Sempra Global	Sempra Global.
South Carolina E&G	South Carolina Electric & Gas Company.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern	Southern Company Services, Inc.
Southwest Transmission	Southwest Area Transmission Sub-Regional Planning Group.
Southwestern Coop	Southwestern Electric Cooperative, Inc.
SPP	Southwest Power Pool, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Suez Energy NA	Suez Energy North America, Inc.
Tacoma	Tacoma Power.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
TransAlta	TransAlta Energy Marketing (US) Inc.
TranServ	TranServ International, Inc.
Tucson	Tucson Electric Power Company.
TVA	Tennessee Valley Authority.
Utah Municipals	Utah Associated Municipal Power Systems.
WAPA	Western Area Power Administration.
WECC	Western Electricity Coordinating Council.
WestConnect	WestConnect Companies.
Western Governors	Western Governors' Association.
Williams	Williams Power Company, Inc.
Wisconsin Electric	Wisconsin Electric Power Company.
WSPP	Western Systems Power Pool, Inc.

INITIAL COMMENTERS—Continued

Abbreviation	Initial commenters
Xcel	Xcel Energy Services, Inc.

REPLY COMMENTERS

Abbreviation	Reply commenters
Alberta Intervenors	Alberta Intervenors (TransCanada Energy Ltd., ENMAX Energy Marketing, Inc.; EPCOR Merchant and Capital, LP; and TransAlta Corporation).
Anaheim	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
APPA	American Public Power Association.
Barrick	Barrick Goldstrike Mines Inc.
Bonneville	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
California Commission	Public Utilities Commission of the State of California.
Canadian Electricity Association	Canadian Electricity Association.
Chandley-Hogan	John D. Chandley and William W. Hogan.
CMUA	California Municipal Utilities Association.
ColumbiaGrid	ColumbiaGrid Members (Bonneville Power Administration; Avista Corp.; Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc.; Seattle City Light; and Tacoma Power.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Detroit Edison	Detroit Edison Co.
Duke	Duke Energy Corp.
Dynegy	Dynegy Power Marketing, Inc.
East Texas Cooperatives	East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn Generation and Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
EEI	Edison Electric Institute.
ElectriCities	ElectriCities of North Carolina, Inc.
Entegra	Entegra Power Group LLC and LS Power Associates, L.P.
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina.
Fertilizer Institute	Fertilizer Institute.
FMPA	Florida Municipal Power Agency and Midwest Municipal Transmission Group.
Great Northern	Great Northern Power Development, L.P.
Hoosier	Hoosier Energy Rural Electric Cooperative, Inc.
H.Q. Energy	H.Q. Energy Services (U.S.), Inc.
Indianapolis Power	Indianapolis Power & Light Co.
Industrial Customers of Northwest Utilities	Industrial Customers of Northwest Utilities (Air Liquide; Air Products; BPB Gypsum, Inc.; Blue Heron Paper Company; Boeing; Boise Cascade; CNC Containers, Northwest; Chemi-Con Materials Corporation; Dyno Nobel, Inc.; ConAgra Foods; Eka Chemicals, Inc.; Evanite Fiber; Georgia-Pacific; Grays Harbor Paper, L.P.; Hewlett-Packard; Inland Empire Paper Co.; Intel; J.R. Simplot; Kimberly-Clark Corporation; Longview Fibre; Microsoft Corporation; Norpac Foods; Noveon Kalama, Inc.; Oregon Steel Mills; PCC Structurals, Inc.; Ponderay Newsprint Co; Shell Oil Products US; Simpson Paper; Simpson Timber; Solar Grade Silicon LLC; SP Newsprint Co.; Tesoro Refining and Marketing Co.; Wah Chang; West Linn Paper Company; Weyerhaeuser).
International Transmission	International Transmission Co. d/b/a ITC*Transmission* and Michigan Electric Transmission Co., LLC.
ISO/RTO Council	ISO/RTO Council.
Lassen	Lassen Municipal Utility District.
LPPC	Large Public Power Council.
MAPP	Mid-Continent Area Power Pool.
Mark Lively	Mark B. Lively.
MDEA	Mississippi Delta Energy Agency, Clarksdale Public Utilities Commission, Public Service Commission of Yazoo City, Arkansas Electric Cooperative Corporation, Municipal Energy Agency of Mississippi, and Lafayette Utilities System*.[1008]
MidAmerican	MidAmerican Energy Company and PacifiCorp.
MISO	Midwest Independent Transmission System Operator, Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NARUC	National Association of Regulatory Utility Commissioners.
NC Transmission Planning Participants	North Carolina Transmission Planning Collaborative Participants.
NCPA	Northern California Power Agency.
Newmont Mining	Newmont USA Limited, dba Newmont Mining Corp.
North Carolina Commission	North Carolina Utilities Commission; Public Staff of the North Carolina Utilities Commission; and the Attorney General of the State of North Carolina.

REPLY COMMENTERS—Continued

Abbreviation	Reply commenters
Northwest IOUs	Northwest Investor-Owned Utilities (Avista Corp., Portland General Electric Co., and Puget Sound Energy, Inc.).
NorthWestern	NorthWestern Corporation.
NRECA	National Rural Electric Cooperative Association.
Occidental	Occidental Chemical Corporation.
OG&E	Oklahoma Gas and Electric Company.
Ohio Power Siting Board	Ohio Power Siting Board, American Municipal Power-Ohio, Inc. and Buckeye Power, Inc.
Old Dominion	Old Dominion Electric Cooperative; Southern Maryland Electric Cooperative, Inc.; Allegheny Electric Cooperative, Inc.; and North Carolina Electric Membership Corporation.
Omaha Public Power	Omaha Public Power District.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
PJM	PJM Interconnection, LLC.
PNM-TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Co. d/b/a Progress Energy Carolinas and Florida Power Corp., d/b/a Progress Energy Florida; and Progress Ventures, Inc.).
Project for Sustainable FERC Energy Policy	Project for Sustainable FERC Energy Policy (Delaware Division of the Public Advocate, Environmental Law & Policy Center, Fresh Energy, Natural Resources Defense Council, Northwest Energy Coalition, Pace Energy Project, Project for Sustainable FERC Energy Policy, Renewable Northwest Project, West Wind Wires, and Wind on the Wires).*
Public Power Council	Public Power Council.
Sacramento	Sacramento Municipal Utility District.
Salt River	Salt River Project Agricultural Improvement and Power District.
Santa Clara	City of Santa Clara, California d/b/a Silicon Valley Power.
Seattle	City of Seattle—City Light Department.
Seminole	Seminole Electric Cooperative, Inc.
South Carolina E&G	South Carolina Electric & Gas Company.
Southern	Southern Company Services, Inc.
SPP	Southwest Power Pool, Inc.
Steel Manufacturers Association	Steel Manufacturers Association.
Strategic Energy	Strategic Energy, L.L.C.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Transparent Dispatch Advocates	PJM Interconnection, LLC; Electric Consumers Resource Council; Electric Power Supply Association; Natural Resources Defense Council; Renewable Northwest Project; Project for Sustainable FERC Energy Policy; Center for Energy Efficiency & Renewable Technologies; Shell Trading Gas and Power Company; American Wind Energy Association; and Exelon.
Utah Municipals	Utah Associated Municipal Power Systems.
WestConnect	WestConnect Companies.
Williams	Williams Power Company, Inc.
Wolverine	Wolverine Power Supply Cooperative, Inc.
WPS Companies	WPS Companies (Wisconsin Public Service Corporation and Upper Peninsula Power Company).
WSPP	Western Systems Power Pool, Inc.
Xcel	Xcel Energy Services, Inc.

TECHNICAL CONFERENCE COMMENTERS

Abbreviation	Technical conference commenters
APPA*	American Public Power Association.
APS*	Arizona Public Service Company.
Bonneville*	Bonneville Power Administration.
Constellation*	Constellation Energy Group, Inc.
EEI*	Exelon Corporation on behalf of Edison Electric Institute (EEI).
EPSA*[1009]	Electric Power Supply Association.
Exelon*	Exelon.
NAESB*	North American Energy Standards Board.
NARUC*	National Association of Regulatory Utility Commissioners.
National Grid*	National Grid USA.
National Grid/Central Hudson	National Grid USA, Central Hudson Gas & Electric Corporation, and American Wind Energy.
NERC*	Prague Power, LLC, on behalf of the North American Electric Reliability Corporation.

TECHNICAL CONFERENCE COMMENTERS—Continued

Abbreviation	Technical conference commenters
New York Parties	Consolidated Edison Co. of New York, Inc., Orange and Rockland Utilities, Inc., New York Power Authority, and Independent Power Producers of New York, Inc.
NRECA*	Great River Energy on behalf of National Rural Electric Cooperative Association (NRECA).
NRG on behalf of EPSA*	NRG Energy, Inc. on behalf of Electric Power Supply Association (EPSA).
PacifiCorp	PacifiCorp.
PJM*	PJM Interconnection, LLC.
AWEA*	PPM Energy, Inc. on behalf of American Wind Energy Association
Progress Energy*	Progress Energy, Inc. (Carolina Power & Light Company, d/b/a. Progress Energy Carolinas, Inc. and Florida Power Corporation, d/b/a Progress Energy Florida, Inc.).
Renewable Northwest Project*	Renewable Northwest Project.
San Diego G&E	San Diego Gas & Electric Company.
TAPS*	Southern Minnesota Municipal Power Agency and Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern*	Southern Company Services, Inc.
WECC*	Western Electricity Coordinating Council.
Williams*	Williams Power.
Williams*	Williams Power Company, Inc.
Xcel*	Xcel Energy Services, Inc.

SUPPLEMENTAL COMMENTERS

Abbreviation	Supplemental commenters
Alabama Commission	Alabama Public Service Commission.
Ameren	Ameren Services Company.
APPA	American Public Power Association.
Barrick	Barrick Goldstrike Mines Inc.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
California Commission	Public Utilities Commission of the State of California.
Community Power Alliance	Community Power Alliance Members (Entergy, Progress Energy, Salt River Project Agricultural Improvement and Power District, and Southern Co.).
Constellation	Constellation Energy Group, Inc.
Duke	Duke Energy Corp.
E.ON	E.ON U.S. LLC.
EEI	Edison Electric Institute.
Entergy	Entergy Services, Inc.
EPSA and AWEA	Electric Power Supply Association and American Wind Energy Association.
Florida Commission	Florida Public Service Commission.
Georgia Commission	Georgia Public Service Commission.
LPPC	Large Public Power Council.
Mark Lively	Mark B. Lively.
MISO	Midwest Independent Transmission System Operator, Inc.
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company.
North Carolina Commission	North Carolina Utilities Commission; Public Staff of the North Carolina Utilities Commission; and the Attorney General of the State of North Carolina.
NRECA	National Rural Electric Cooperative Association.
OG&E	Oklahoma Gas and Electric Company.
Pacific Coast Parties	Pacific Coast Parties (Avista Corporation, Bonneville Power Administration, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., the Sacramento Municipal Utility District and the Transmission Agency of Northern California).
PGP	Public Generating Pool.
Southwest Utilities	Pinnacle West Companies, Public Service Company of New Mexico, Texas-New Mexico Power Company, and UniSource Energy Corporation.
PNM-TNMP	Public Service Company of New Mexico and Texas-New Mexico Power Company.
Powerex	Powerex Corp.
PPL	PPL Companies.
PPM	PPM Energy, Inc.
Progress Energy	Progress Energy, Inc. (Carolina Power & Light Company, d/b/a. Progress Energy Carolinas, Inc. and Florida Power Corporation, d/b/a Progress Energy Florida, Inc.).
Progress Energy and MidAmerican	Progress Energy, Inc. and MidAmerican Energy Company.
Public Power Council	Public Power Council.
SEARUC	Southeastern Association of Regulatory Utility Commissioners.
South Carolina E&G	South Carolina Electric & Gas Company.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.

SUPPLEMENTAL COMMENTERS—Continued

Abbreviation	Supplemental commenters
Southern	Southern Company Services, Inc.
Tacoma	Tacoma Power.
TAPS	Transmission Access Policy Study Group.
TDU Systems	Transmission Dependent Utilities Systems.
Transparent Dispatch Advocates	Transparent Dispatch Advocates (American Wind Energy Association; Center for Energy Efficiency & Renewable Technologies; Electric Consumers Resource Council; Electric Power Supply Association; Exelon Corporation; Natural Resources Defense Council; PJM Interconnection, LLC; PPM Energy; Project for Sustainable FERC Energy Policy; Renewable Northwest Project; and Shell Trading Gas and Power Company)*[1010]
Western Governors	Western Governors' Association.
Williams	Williams Power Company, Inc.
WIRES	WIRES.
Xcel	Xcel Energy Services, Inc.

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[1008] A "*" indicates that the composition of this group has altered in the reply comment filing.

[1009] A "*" indicates that this party submitted speaker materials at the October 12 Technical Conference.

[1010] A "*" indicates that the composition of this group has altered in this filing.

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I. Common Service Provisions

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Ratio Share

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Transmission Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate

transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This 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 and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to the longer of a competing request by any new Eligible Customer or five years and to pay the current just and reasonable rate, as approved by the Commission, for such service. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to [the acceptance by the Commission of the Transmission Provider's Attachment K], unless terminated, will become subject to the five year/one year requirement on the first rollover date after [the acceptance by the Commission of the Transmission Provider's Attachment K].

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—

Spinning, (iv) Operating Reserve—Supplemental, and (v) Generator Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5, 6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) Any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service

Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR part 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 CFR part 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on its public Web site all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS an electronic link to these rules, standards and practices, and shall post on its public Web site an electronic link to the NAESB Web site where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also make available on its public Web site a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are posted on its website. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local

furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

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 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.

7.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules

and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment L.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or
2. One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, *i.e.*, in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among

requests with the same duration and pre-confirmation status (Pre-Confirmed or not confirmed), priority will be given to an Eligible Customer's request that offers the highest price, followed by the date and time of the request.

(iii) If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration requests, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, pre-confirmation status, price and time of response will be used to determine the order by which the multiple shorter duration requests will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in **Federal Register**] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission

Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) Immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to

comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 14, 2007 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (*e.g.*, hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such

notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation To Provide Transmission Service That Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service

Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible

Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service

The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If the Eligible Customer does not pay this non-refundable reservation fee within 15 days of notifying the Transmission Provider it intends to extend the commencement of service, then the Eligible Customer's application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application

A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating whether the Transmission Customer commits to a Pre-Confirmed Request, *i.e.*, will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-to-Point Transmission Service

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily

service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-to-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects not to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by a Transmission Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by a Transmission Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required

Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure To Meet Study Deadlines

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

20 Procedures if the Transmission Provider Is Unable To Complete New Transmission Facilities for Firm Point-to-Point Transmission Service

20.1 Delays in Construction of New Facilities

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission

Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such 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 shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement with the Assignee. The

Assignee must execute a service agreement with the Transmission Provider prior to the date on which the reassigned service commences that will govern the provision of reassigned service. The Transmission Provider shall credit or charge the Reseller, as appropriate, for any differences between the price reflected in the Assignee's Service Agreement and the Reseller's Service Agreement with the Transmission Provider. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its

Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, 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.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

• Unit size and amount of capacity from that unit to be designated as Network Resource

• VAR capability (both leading and lagging) of all generators

• Operating restrictions

—Any periods of restricted operations throughout the year

—Maintenance schedules

—Minimum loading level of unit

—Normal operating level of unit

—Any must-run unit designations required for system reliability or contract reasons

• Approximate variable generating cost ($/MWH) for redispatch computations

• Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

• Identification of the Network Resource as an off-system resource

• Amount of power to which the customer has rights

• Identification of the control area(s) from which the power will originate

• Delivery point(s) to the Transmission Provider's Transmission System

• Transmission arrangements on the external transmission system(s)

• Operating restrictions, if any

—Any periods of restricted operations throughout the year

—Maintenance schedules

—Minimum loading level of unit

—Normal operating level of unit

—Any must-run unit designations required for system reliability or contract reasons

• Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

• Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

• Operating restrictions needed for reliability

• Operating guides employed by system operators

• Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

• Location of Network Resources described in subsection (v) above

• 10 year projection of system expansions or upgrades

• Transmission System maps that include any proposed expansions or upgrades

• Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions:

(1) The Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are

integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the [the effective date of a Final Rule in RM05–25–000], the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (*e.g.* the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible

Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure To Meet Study Deadlines

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33 Load Shedding and Curtailments

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network

Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation Under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and

operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 CFR 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Schedule 1—Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2—Reactive Supply and Voltage Control From Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) Deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/−1.5 percent up to 7.5 percent

(or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $____/KW of Reserved Capacity per year.

(2) Monthly delivery: $____/KW of Reserved Capacity per month.

(3) Weekly delivery: $____/KW of Reserved Capacity per week.

(4) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $____/KW of Reserved Capacity per month.

(2) Weekly delivery: $____/KW of Reserved Capacity per week.

(3) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Schedule 9—Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another

Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) Deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/−1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched to supply the Transmission Provider's Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Attachment A—Form Of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider), and _____ (''Transmission Customer'').

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

_____

_____

Transmission Customer:

_____

_____

_____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

_____

Name

_____

Title

_____

Date

Transmission Customer:

By:

_____

Name

_____

Title

_____

Date

Specifications for Long-Term Firm Point-to-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

_____

3.0 Point(s) of Receipt: _____

Delivering Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): __

6.0 Designation of party(ies) subject to reciprocal service obligation: _____

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service: _____

_____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: _____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge: __

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

Attachment A–1—Form of Service Agreement for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider), and _____ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which

the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller, as identified below, of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee and appropriately specified in this Service Agreement. Such negotiated terms and conditions include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit or charge the Reseller, as appropriate, for any difference between the price reflected in the Assignee's Service Agreement and the Reseller's Service Agreement with the Transmission Provider.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

_____

Name

_____

Title

_____

Date

Assignee:

By:

_____

Name

_____

Title

_____

Date

Specifications for the Resale, Reassignment or Transfer of Long-Term Firm Point-to-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. _____

_____

3.0 Point(s) of Receipt: _____

Delivering Party: _____

4.0 Point(s) of Delivery: _____

Receiving Party: _____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation: _____

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service: _____

_____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: _____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge: __

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

Attachment B—Form of Service Agreement for Non-Firm Point-to-Point Transmission Service

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider), and _____ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

_____

_____

Transmission Customer:

_____

_____

_____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

_____

Name

_____

Title

_____

Date

Transmission Customer:

By:

_____

Name

_____

Title

_____

Date

Attachment C—Methodology To Assess Available Transfer Capability

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and

(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

(a) For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(b) For ETC, a transmission provider shall explain: (i) its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non-OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; and (v) its processes for ensuring that non-firm capacity is released

properly (*e.g.*, when real time schedules replace the associated transmission service requests in its real-time calculations).

(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall:

(i) explain its definition of AFC; (ii) explain its AFC calculation methodology; (iii) explain its process for converting AFC into ATC for OASIS posting; (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(d) For TRM, a Transmission Provider shall explain: (i) its definition of TRM; (ii) its TRM calculation methodology (*e.g.*, its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.

(e) For CBM, the Transmission Provider shall state include a specific and self-contained narrative explanation of its CBM practice, including: (i) an identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (*e.g.*, probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.

(f) In addition, for CBM, a Transmission Provider shall: (i) explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

(g) The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.

Attachment D—Methodology for Completing a System Impact Study

To be filed by the Transmission Provider

Attachment E—Index of Point-To-Point Transmission Service Customers

Customer
Date of Service Agreement

Attachment F—Service Agreement for Network Integration Transmission Service

To be filed by the Transmission Provider

Attachment G—Network Operating Agreement

To be filed by the Transmission Provider

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be _____.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer
Date of Service Agreement

Attachment J—Procedures for Addressing Parallel Flows

To be filed by the Transmission Provider

Attachment K—Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, 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 nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05–25–000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05–25–000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop 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; and

(viii) The relevant cost allocation procedures or principles.

Attachment L—Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit.

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) a summary of the procedure for determining the level of secured and unsecured credit;

(2) a list of the acceptable types of collateral/security;

(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;

(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;

(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and

(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

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